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TALISMAN

E N E R G Y

OUR MISSION:
VALUE CREATION
IN THE GLOBAL
UPSTREAM OIL
AND GAS BUSINESS



2003 ANNUAL REPORT

Talisman Energy Continues to Create Value for Its Shareholders

Talisman Energy Inc. is a large independent oil and gas producer with global operations. Talisman's common shares are widely held and listed on the Toronto and New York stock exchanges under the symbol TLM. The Company had 128 million shares outstanding at year end 2003.

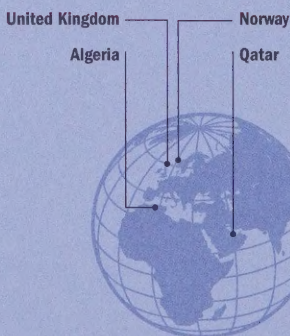
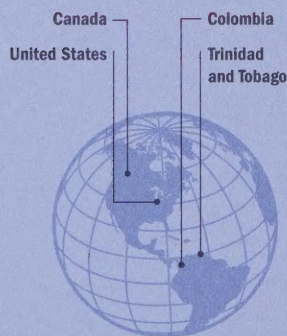
Talisman is a \$12 billion company, employing 1,758 people in its North American and international operations. The Company's headquarters are in Calgary, Alberta, Canada.

Established as an independent company in 1992, Talisman has a track record of growth and creating value for its shareholders. Over the past 11 years, the Company has grown production per share at an average compound annual rate of 10% and is committed to continuing production per share growth of at least 5-10% per annum.

Talisman generated a record \$2.7 billion in cash flow in 2003. The Company produced 398,000 boe/d and at year end had 1.4 billion boe of proved reserves that are predominantly natural gas and light oil. During 2003, Talisman repurchased 3.3 million shares and reduced long-term debt by \$800 million. Talisman plans to spend \$2.3 billion on exploration and development in 2004.

Talisman has a strong commitment to its stakeholders, including shareholders, debt holders, employees, customers, suppliers, governments and the communities where it operates. The Company is committed to high standards of social and environmental responsibility wherever it does business.

Talisman's Unique Positioning Provides a Competitive Advantage



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The President's Report



Dr. James W. Buckee
President and Chief Executive Officer

Talisman's mission is to create value for its shareholders in the upstream oil and gas business. What differentiates us from other large independents is that Talisman is a successful international operator, as well as a major North American gas producer.

From inception, we had the view that Western Canada was mature and that bigger prizes lie elsewhere. The confidence and competence to operate internationally arose partly because Talisman was founded from a Canadian subsidiary of one of the super-majors and many of our senior technical and management staff had extensive international experience. Since then, we have generated our own internal technical and commercial expertise.

Our current positioning has been achieved by consistently executing our strategy over the past 11 years. In 1992, when Talisman was created, the Company produced about 51,000 boe/d, with operations solely in Canada.

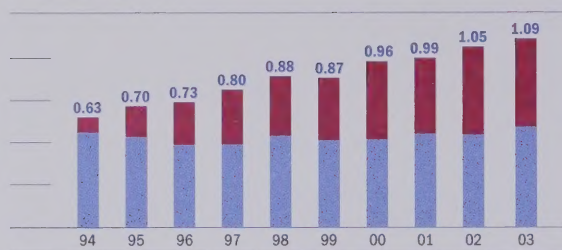
Through a number of corporate and asset acquisitions, Talisman quickly established operations in the North Sea, North Africa and Southeast Asia and subsequently added value through the drill bit. Increasing size and experience became an advantage in the international business, allowing Talisman to take on larger projects and undertake more high impact exploration.

About the Cover

This is the Central Processing Platform in the Block PM-3 Commercial Arrangement Area in Malaysia/Vietnam. Talisman completed the \$1 billion oil and gas project in September 2003.

Production Per Share
(boe, excluding Sudan)

■ North America ■ International



Over the 1992-2003 period, we averaged 20% compound annual production growth and exited 2003 at 437,000 boe/d, effectively replacing production from our previous interests in the Sudan project, which produced about 65,000 bbls/d earlier in the year.

Talisman's Diverse International Portfolio Gives Us a Competitive Advantage

I believe that Talisman now has an enviable set of international exploration and development opportunities. The attraction of international operations will be increasingly evident as the maturity of the North America basins continues to give rise to a sequential increase in both replacement costs and operating costs, while conventional production is declining. Larger companies are finding it increasingly difficult to grow North American production.

Our Goal is to Increase Production per Share by 5-10% Annually

Talisman is committed to growing production per share by 5-10% per annum. We think this is one of the best and most transparent measures of value creation. With our existing prospect inventory, strong balance sheet and demonstrated technical and commercial expertise, I am confident we can achieve these growth rates in 2004, 2005 and 2006.

We will continue to target selected North American gas opportunities and large international development opportunities. With our focus on the Canadian Foothills, the relatively under explored Deep Basin in Alberta and the Appalachian basin in the eastern United States, we believe we can continue to grow our North American gas production and generate surplus cash for opportunities elsewhere.

In 2003, Talisman's international production averaged 195,000 boe/d, accounting for approximately 50% of the Company's total. Of this, two-thirds came from the North Sea. However, combined production from Malaysia, Vietnam, Indonesia, Algeria and Trinidad is expected to grow at rates of approximately 30% compounded annually over the next three years from developments currently underway.

Talisman plans to participate in more higher risk, high reward exploration drilling. We have built an inventory of prospects in Colombia, Qatar, Trinidad and Alaska and are evaluating larger opportunities in the North Sea. If successful, any one of our larger prospects could be material to Talisman. Although the individual risks are higher, we are of sufficient size to drill enough wells to avoid gamblers ruin, while, on the other hand, maintaining strict capital discipline.

Five Years of Cash Flow Growth

Cash flow reached a record high \$2.7 billion or \$21.21 per share in 2003, with Talisman's realized oil and gas prices up 25% over 2002. Net income was also a record high \$1.0 billion, or \$7.65 per share.

Our major achievement last year was the completion and startup of the largest petroleum development ever undertaken by a Canadian company in Southeast Asia. The \$1 billion oil and gas project in the PM-3 Commercial Arrangement Area (CAA) in Malaysia and Vietnam was completed on schedule and on budget. With capacity of 60,000 bbls/d of oil and 270 mmcf/d of natural gas, Talisman's share (41%) of production is just over 40,000 boe/d.

We believe this region holds significant opportunities and potential for Talisman using the same strategy that has proved successful

elsewhere. Our acreage is located in a prolific hydrocarbon basin with substantial remaining potential. Talisman expanded its position in 2003, acquiring a very large offshore block in Vietnam, adjacent to PM-3 CAA. Drilling success continued with five new discoveries in both Malaysia and Vietnam.

Elsewhere in Southeast Asia, we continued to monetize the very large gas reserves in the Corridor Block in Indonesia. Talisman has signed a memorandum of understanding to sell over 2.4 tcf of gas (Talisman 36%) for power generation in West Java. We also commenced gas sales to Singapore. The pipeline between the two countries forms an important link in the trans-Asian gas grid.

2003 — A Pivotal Year

In March, Talisman sold its 25% indirect working interest in the Greater Nile Oil Project in Sudan for \$1.1 billion. I believe Talisman's presence and community development work were highly beneficial. I also think subsequent events will show that the responsible development of hydrocarbon resources will play a fundamental role in the development of the country and will bring great benefits to all the people of Sudan.

In the UK North Sea, Talisman had three successful new exploration wells, which cumulatively tested at over 19,000 bbls/d.

Talisman obtained an entry position in Norway with the acquisition of a 61% interest and operatorship of the Gyda field, which at year end was producing 7,000 boe/d (net Talisman). This was followed by additions to our acreage position both through licence rounds and acquisitions.

First sales from the Ourhoud and MLN fields in Algeria commenced in 2003, reaching 15,000 bbls/d (net Talisman) in December.

In Trinidad, development of the offshore Greater Angostura oil and natural gas project is underway with first oil sales of 18,000-25,000 bbls/d (net Talisman) expected early in 2005. Talisman also started its seismic program on the onshore Eastern Block. This is by far the largest onshore 3D seismic program ever shot in Trinidad.



In Colombia, Talisman drilled its first exploration wells during the year and plans to drill at least one more in 2004.

The Company also made a number of strategic moves in North America in 2003. Talisman completed the acquisition of a number of natural gas properties in the Appalachian basin in upper New York State, with 60 mmcf/d of production and almost 400,000 net acres of land. This is high value gas, close to markets, in a deeper play system that is still relatively unexplored. To date, we have had five successful wells, testing cumulatively at rates of 69 mmcf/d.

We also expanded our midstream operations in west central Alberta with the completion of a pipeline in the Alberta Foothills and the acquisition of gas processing and gathering facilities. These assets complement our other midstream operations in the area and enhance Talisman's ability to control its production, spending and timing in a highly prospective part of the basin.

Talisman also made small but strategic steps into the North American frontiers in 2003. We acquired interests in up to 10 townships (360 square miles) in Alaska and drilled our first well in January 2004. The Company also earned a 30% interest in two offshore blocks in eastern Canada by participating in an exploration well.

High Quality Proved Reserves

Talisman replaced 150% of production from all sources in 2003, including discoveries, net purchases, revisions and transfers, excluding Sudan. On a proved only basis, the comparable number is 127%.

Excluding Sudan, proved reserves increased 3% to 1,362 mmbbls of oil equivalent. In addition, Talisman has 873 mmboe of probable reserves, equating to a reserve life index of 16 years. Approximately 60% of our reserves are natural gas and the remainder light-medium quality crude oil and natural gas liquids.

Finding and development costs increased to \$14.28/boe (US\$11.71/boe net) in 2003, however, this doesn't reflect over 100 mmboe of international probable reserves that we expect will be booked as proved in 2004. Had these been included last year, the net effect would have been to lower our finding and development costs to under \$8.50/boe. The disconnect between capital spending and reserves booking, particularly on the international side makes Talisman's three year average finding and development cost of \$8.76/boe (US\$7.72 net) a more representative number.

Although finding and development costs in North America are generally increasing, this is a direct reflection of the maturity of the basin.

Over the past two years, Talisman has played a leading role in the Alberta Securities Commission (ASC) process to develop new disclosure standards for reserves. We support the objective of fostering investor confidence in reserves and have advocated uniformity with our North American peer group. In response to the ASC recommendations, Talisman reviewed its procedures for

evaluating and booking reserves. The Company also established a committee of the Board of Directors to review reserves processes and disclosure and has established the position of an internal qualified reserves evaluator (IQRE). The IQRE provides a report to the Reserves Committee and a regulatory certificate regarding reserves and related cash flows. We continue to do a complete internal evaluation of proved reserves annually, supported by external audits. Approximately 90% of Talisman's proved reserves have been independently audited over the past three years. I am confident that Talisman's reserves booking procedures and internal controls accurately capture and report our reserves. The empirical evidence for this is our growing production, positive historical reserves revisions and low percentage of proved undeveloped reserves in North America.

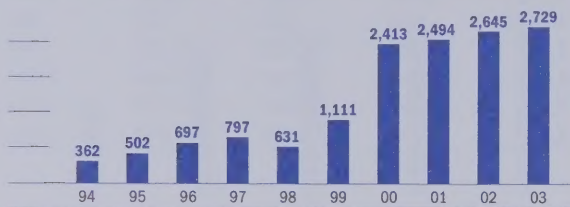
Continued Financial Strength

Talisman's cash flow increased for the fifth consecutive year. With increases from Malaysia/Vietnam and Algeria, production in the fourth quarter averaged 419,000 boe/d. Excluding Sudan, this represented organic growth of 10% over the fourth quarter of 2002 and 15% production per share growth. Talisman's shares reached a record high \$81.80 in early March 2004, which in my opinion doesn't reflect the full value of our assets and opportunities.

During the year, Talisman repurchased 3.3 million common shares, reduced long term debt by \$800 million and increased its annual dividend rate from \$0.60 to \$0.80 per common share. The Company has also adopted a cash payment feature for stock options, which is tax effective for the Company and better addresses the issue of reporting option expenses. However, since the ongoing income exposure is based on Talisman's share price performance, the change also had the effect of lowering reported net income by \$130 million as Talisman share prices continued to climb. More importantly, we expect that very few shares will be issued from treasury in the future compared to the stock option program before it was amended.

Cash Flow

(millions of Canadian dollars)



2004 – A Year of Momentum and Growth

We enter 2004 in excellent financial health, with quality producing assets, a solid reserves base and an opportunity set that we expect will provide built-in growth for several years. Our production guidance for 2004 is 415,000-445,000 boe/d, consistent with the objective of 5-10% annual production per share growth. We plan to spend \$2.3 billion, with two-thirds of this directed at development projects and one-third for exploration.

A major milestone this year will be completion of the Greater Angostura development in Trinidad, which will contribute to continued production growth in 2005.

Energy is a Vital Business and Talisman is Well Positioned

Key to Talisman's strategy is a belief that energy is a vital but finite resource. The OECD countries enjoy a standard of living that is heavily dependent on energy, while at the same time the energy demands of developing countries are increasing rapidly. World oil demand reached an all time high in 2003. Total consumption was 28.6 billion barrels, with demand in the emerging market economies growing by 2.3% over the prior year.

Even at current prices, crude oil and natural gas will continue to dominate the energy mix. History has taught us that commodity prices are volatile and we cannot predict the next cycle. However, the world continues to consume hydrocarbons, particularly oil, at rates faster

than reserves are being replaced. The challenge for the industry is to meet these growing energy demands.

Despite higher prices, the oil and gas industry is struggling to increase production. It is estimated that natural gas production from the largest 100 North American producers fell by 3-4% in 2003.

This supply tightness in both oil and natural gas has produced a step change in prices. Talisman is well positioned to benefit from these higher prices with its substantial North American gas production and increasing international oil production. Talisman realized an average netback of \$23/boe in 2003, a record high.

We continued to develop and implement our corporate responsibility program in 2003 and revised our Policy on Business Conduct and Ethics to better reflect our position on issues such as human rights, security and community relations. Talisman is committed to providing a safe work place and operating in an environmentally responsible fashion. I believe that we must continue our efforts to publicly report on our social, environmental and economic performance in a balanced manner, to allow stakeholders to develop a more complete picture of our positive impact on society.

I would like to thank Talisman's employees and contractors for their hard work and commitment. I would also like to acknowledge the guidance and help of the Board of Directors. In particular, I will miss the contribution and wise counsel of Roland Priddle, who is retiring after four years on the Board.

Talisman will continue to generate wealth for our shareholders, and be an exciting and rewarding place to work. I see a bright future ahead.

J.W. Buckee
President and Chief Executive Officer
March 3, 2004

	2003	2002	2001	2000	1999
Financial (millions of Canadian dollars)					
Cash flow ¹	2,729	2,645	2,494	2,413	1,111
Net income	1,007	524	733	857	255
Exploration and development expenditures	2,180	1,848	1,882	1,179	996
Total assets	11,365	11,594	10,819	8,625	7,806
Long-term debt	2,203	2,997	2,983	1,733	2,195
Shareholders' equity	4,959	4,502	4,126	3,614	3,621
Production (daily average production) ²					
Oil and liquids (bbls/d)					
North America	59,578	62,676	66,056	66,374	58,489
North Sea	113,075	127,486	110,828	111,902	59,256
Southeast Asia	24,430	22,469	20,873	20,206	28,852
Algeria	6,594	—	—	—	—
Sudan	13,039	60,109	53,257	45,869	11,726
Total oil and liquids	216,716	272,740	251,014	244,351	158,323
Natural gas (mmcf/d)					
North America	864	820	809	755	681
North Sea	109	122	108	122	115
Southeast Asia	117	94	93	111	108
Total natural gas	1,090	1,036	1,010	988	904
Total mboe/d ^{2,4}	398	445	419	409	309
Total mboe/d (net of royalties) ^{3,4}	334	366	337	335	259
Shares outstanding at December 31 (millions)	128	131	134	135	138
Number of permanent employees at December 31	1,758	1,565	1,358	1,263	1,113

1 Non-GAAP measure. See inside back cover.

2 Production numbers are before royalties, unless otherwise indicated.

3 Net production (after royalties).

4 Six mcf of natural gas equals one boe.

Additional information for US Readers can be found on page 76.

Reserves and Finding and Development Costs

Talisman replaced approximately 150% of its production in 2003 (excluding Sudan) from all sources, including discoveries, net acquisitions, revisions and transfers (proved and probable). Talisman's proved reserves (excluding Sudan) increased 3%, totaling 1.36 billion boe at year end. Net reserves (after royalties, excluding Sudan) increased 4% to 1.09 billion boe. Approximately 40% of the Company's reserves are medium-light quality oil and liquids and 60% are natural gas.

Finding and development costs averaged \$14.28/boe for the year (US\$11.71/boe net). However, Talisman believes the three-year average results better reflects its ongoing performance. At year end, Talisman had over 100 mmboe of probable international reserves pending booking as proved.

	2003		3-year Average	
(\$/boe)	C\$ Gross ¹	US\$ Net ²	C\$ Gross ¹	US\$ Net ²
Finding and development costs	14.28	11.71	8.76	7.72
Finding and development and acquisition costs ³	14.67	12.12	9.79	8.62

1 Gross proved reserves before deduction of royalties.

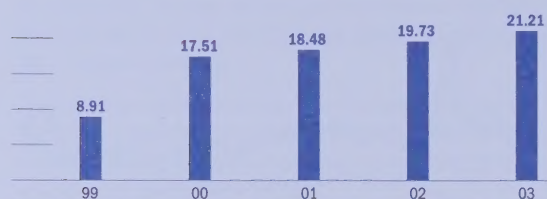
2 Net proved reserves after deduction of royalties.

3 Excludes Sudan sale.

For additional details on Talisman's reserves and finding and development costs, please see pages 75-77 and 83-86.

Talisman at a Glance

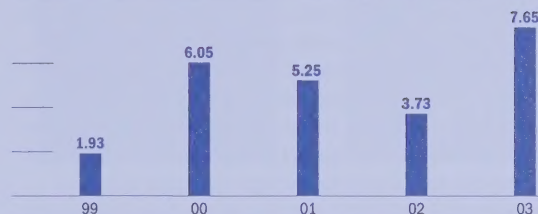
Cash Flow Per Share¹ (dollars)



¹ Non-GAAP measure. See inside back cover.

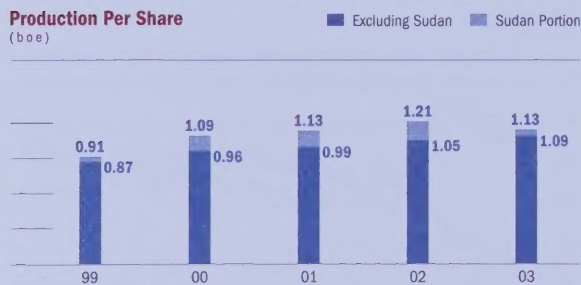
Cash flow per share increased for the fifth straight year to a record \$21.21. Higher oil and natural gas prices and increased natural gas volumes offset lower oil volumes and higher royalties.

Earnings Per Share (dollars)



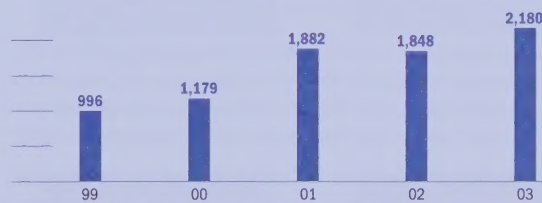
Talisman's earnings per share more than doubled in 2003 with the gain on the sale of the Sudan interests, higher cash flow and tax rate reductions.

Production Per Share (boe)



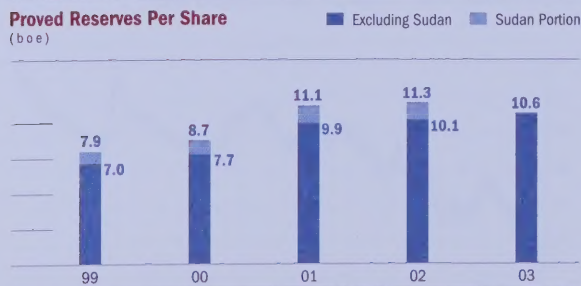
Production per share increased 4% last year, excluding Sudan. Talisman repurchased 3.3 million shares during 2003.

Exploration and Development Spending (millions of dollars)



Exploration and development spending was \$2,180 million. North America accounted for half of this spending.

Proved Reserves Per Share (boe)



Gross proved reserves per share, excluding Sudan, increased by 5% in 2003.

Netbacks (\$/boe)

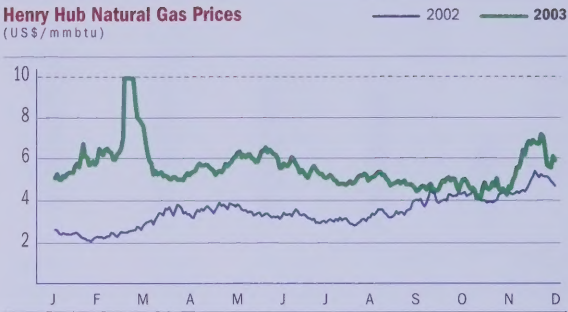


Talisman's netbacks increased \$2.66/boe in 2003, largely on the strength of a 61% increase in the Company's realized natural gas price in North America.

Business Environment

Natural Gas Prices

North American natural gas prices averaged US\$5.44/mmbtu at Henry Hub, an increase of 60% over 2002. Higher prices have prompted an increase in drilling activity; however, production amongst the large producers declined by an estimated 3-4% in 2003. North American gas production is likely at or near effective capacity for the first time in the history of the industry. Gas to gas competition, which was the dominant feature of the marketplace, has virtually disappeared and the lack of incremental supplies and high prices have effectively capped demand. Early in 2004, gas prices remain above US\$5/mmbtu, however, both weather and economic growth will continue to have a major influence on price. Talisman is forecasting NYMEX prices to average between US\$4.75-5.50/mmbtu in 2004.



Oil Prices

WTI prices increased 19%, averaging US\$30.99/bbl as world oil demand grew by an estimated 2%, led by growth in China and other emerging market economies. However, in many parts of the world the price of oil fell in local currency due to a weaker US dollar.

Lower production from Iraq was offset by increases from other OPEC countries and growing production from the former Soviet Union. Prices have remained high in early 2004 in part because strong demand and anemic supply continued to keep inventories at historically low levels.

Talisman is using a forecast for WTI of US\$25-30/bbl in 2004, which may prove to be conservative. However, much depends on economic and energy demand growth and OPEC's willingness to continue to cut production if demand weakens.

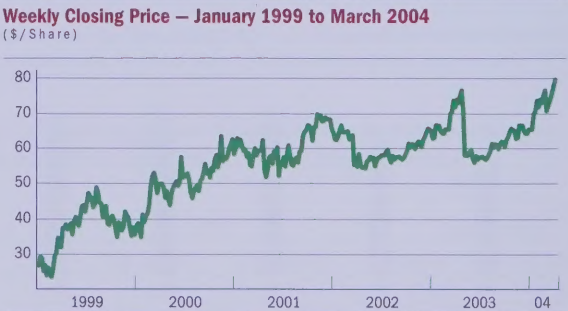


Share Price Performance

Talisman's shares reached an all time high in 2003, closing the year at \$73.52, a 29% increase over year end 2002. This was likely due to high commodity prices, the Company's continuing guidance of 5-10% production per share growth, Talisman's opportunity set and strong balance sheet.

Market indices in general were up last year. The S&P/TSX Composite increased 24%, with continuing low interest rates, high levels of consumer confidence and continued economic growth.

High commodity prices buoyed the oil and gas sector and the average share price for Talisman's Canadian and US peers increased 23% over the 2002 close.



The Management Team

Our Mission is to Create Value in the Upstream Oil and Gas Business

To achieve this, Talisman will continue to develop its large North American gas business, with significant growth expected from its international operations.

The Company's international assets provide large opportunities outside the mature North American sedimentary basins. Talisman continues to build new core areas based on materiality, growth potential and competitive advantage.

Talisman owns, operates and controls key assets and infrastructure where they provide a competitive advantage or add value.

Talisman operates over three-quarters of its production in North America, 60% in the North Sea and is the operator of major projects in Southeast Asia. This control has contributed to the Company's success, adds value and enables Talisman to influence costs and timing.

Talisman will grow through both exploration and acquisitions, creating opportunities that add significant shareholder value.

In addition, the Company is pursuing selected, higher impact, higher risk exploration targets.



Jim Buckee
President and Chief
Executive Officer



Ron Eckhardt
Executive Vice-President,
North American Operations



Nigel Hares
Executive Vice-President,
Frontier and International
Operations



Joe Horler
Executive Vice-President,
Marketing



Mike McDonald
Executive Vice-President,
Finance and Chief
Financial Officer



Bob Redgate
Executive Vice-President,
Corporate Services



Jackie Sheppard
Executive Vice-President,
Corporate and Legal, and
Corporate Secretary



John 't Hart
Executive Vice-President,
Exploration

Objectives and Performance

Objectives from Talisman's 2002 Annual Report

- The sale of the interests in the Sudan properties was expected to close in the first quarter of 2003.
- The Company's objective was to grow production per share by 5-10% in 2003 and 2004 (excluding Sudan).
- Talisman expected to participate in 700 exploration and development wells, spending \$2.1 billion.
- Significant production increases were expected from Malaysia, Vietnam and Algeria in the second half of 2003.
- Unit operating costs were expected to average approximately \$7.00/ boe.
- The Company expected cash flow per share of over \$21 in 2003, based on US\$28.50/bbl WTI oil and US\$5/mcf NYMEX gas.

Performance in 2003

- Talisman completed the sale of its indirect interest in the Sudan properties for \$1.1 billion on March 12.
- In the fourth quarter of 2003, production per share was up 15% (excluding Sudan), compared to fourth quarter 2002.
- In the three quarters following the sale of its interest in the Sudan assets, Talisman's production per share increased 6% over the corresponding period in 2002.
- Talisman participated in 702 wells, with exploration and development spending of \$2.18 billion.
- Fourth quarter 2003 production from these areas averaged 31,000 boe/d, compared to 6,000 boe/d a year earlier.
- Unit operating costs averaged \$7.15/boe.
- Cash flow per share was \$21.21. Although oil and gas prices were higher than expected in US\$ terms, this benefit was offset by the stronger Canadian dollar.

In 2004 ...

- Talisman's production is expected to average between 415,000-445,000 boe/d.
- The Company expects to participate in approximately 640 North American and 118 international gross exploration and development wells.
- Talisman plans to spend \$2.3 billion on exploration and development.
- With the recent strength in the pound sterling, unit operating costs are expected to increase 5-10%.
- Talisman expects to generate \$17-22 cash flow per share. This is based on US\$25-30/bbl WTI oil prices, US\$4.75-5.50/mmbtu NYMEX gas prices and a Canadian dollar exchange rate of US\$0.73-0.77.

Other 2003 Highlights ...

- Record high closing share price.
- Net debt down \$800 million.
- Annual dividend rate increased to \$0.80/share.
- Repurchase of 3.3 million shares.



Operations and Exploration Areas

*Talisman has assembled a unique set of assets.
The Company will continue to grow its large North
American natural gas business while pursuing
world scale International opportunities.*



Talisman's Edson Gas Plant

North America

Talisman's large North American gas business generates well in excess of \$1 billion/year in cash that is reinvested for growth both here and abroad. The Company focuses on deep, high potential gas plays along the Rocky Mountain Foothills. Talisman has also established a new core gas area in upper New York State. Talisman expects to grow its North American gas production at rates of 3-5% annually over the next five years.

2003 in Review

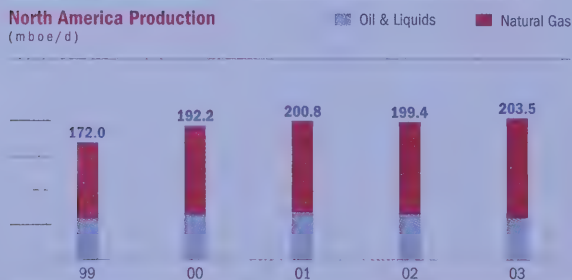
- Natural gas production averaged 864 mmcf/d, up from 820 mmcf/d in 2002.
- Liquids production averaged 59,578 bbls/d, compared to 62,676 bbls/d in 2002.
- Talisman drilled 378 natural gas wells and 204 oil wells with a 93% success rate.
- Exploration and development spending was \$1.1 billion.
- The Company added 74.6 mmboe of proved reserves, excluding revisions and transfers, and had 631 mmboe of proved reserves at year end (93% developed).
- Conventional operating costs averaged \$5.01/boe, up from \$4.65/boe in 2002.
- Talisman drilled 30 successful wells in the Alberta Foothills.
- Talisman completed the construction of and commissioned the Erith pipeline in the fourth quarter of 2003.
- The Company purchased Vista Midstream Solutions Ltd., including the Cutbank gas plant and an extensive gas gathering system.
- Talisman earned a 30% interest in two East Coast offshore exploration licences.
- The Company entered into an agreement to acquire interests in up to 10 townships in Alaska.
- Talisman has tested five wells at combined rates of 69 mmcf/d in the Appalachia region of upper New York State.
- The Company achieved daily production records at Chauvin (16,200 bbls/d), West Whitecourt (56 mmcf/d), Alberta Foothills (160 mmcf/d) and Deep Basin (61 mmcf/d).

2004 Outlook

- Exploration and development spending is expected to be \$1.1 billion, with over 77% directed towards natural gas projects.
- Production targets are 885-905 mmcf/d of natural gas and 54,000-56,000 bbls/d of oil and liquids.
- Talisman plans to participate in 640 wells, including 11 in Appalachia.
- Talisman commissioned a new gas plant in the Turner Valley area in January 2004.
- Talisman plans to spend \$50 million expanding and optimizing its operated pipeline systems and associated infrastructure.
- Talisman drilled its first well in the National Petroleum Reserve Area of the Alaskan North Slope.



North America Production
(mboe/d)



Canada United States



North Sea

In the UK Central North Sea, Talisman has established a number of operated commercial hubs, which provide significant value through low risk development, adjacent exploration opportunities, secondary recovery and third-party tariff receipts. Talisman is also building a new core area in the Norwegian sector of the Central North Sea. The North Sea was Talisman's highest netback area in 2003. The Company has a large drilling program underway designed to increase oil and liquids production by 5-10% in 2005.

2003 in Review

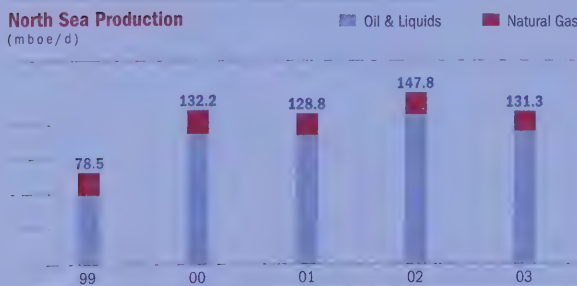
- Liquids production averaged 113,075 bbls/d, compared to 127,486 bbls/d in 2002; however, fourth quarter liquids production recovered to 128,697 bbls/d.
- Natural gas production averaged 109 mmcf/d, compared to 122 mmcf/d in 2002.
- Talisman drilled 17 successful oil and natural gas wells.
- Exploration and development spending was \$496 million.
- Talisman added 54 mmboe of proved reserves and had 299 mmboe of proved reserves at year end (84% developed).
- Operating costs averaged \$11.36/boe, up from \$10.08/boe in 2002.
- First oil from the Blake Flank development started on schedule at 5,200 bbls/d.
- Talisman participated in three successful exploration wells. The J5 well, adjacent to the Buchan field, tested at 7,100 bbls/d, the Tartan North well tested at 8,100 bbls/d and the Affleck well, east of the Orion field, tested at 4,000 bbls/d. The Drum, Dunnottar and Eta-2 wells were unsuccessful.
- The Company acquired an entry position in Norway with the purchase of a 61% operated interest in two blocks in the Norwegian North Sea containing the producing Gyda field and platform facilities and 61% of the Gyda gas export pipeline.
- Talisman was awarded four new exploration blocks in the UK North Sea.

2004 Outlook

- Early in 2004 Talisman was awarded two additional licences in the Norwegian North Sea, one of which is adjacent to the Gyda field. The Company also acquired interests in a further two licences in the area. Talisman plans to drill three wells in Norway in 2004.
- The Tartan North development (Talisman 100%) is expected to start production in the fourth quarter.
- Development approval of the J1/J5 oil project is expected.
- Exploration and development spending is expected to be \$606 million, with \$119 million on exploration and \$487 million on development.
- Production targets are 120-130 mmcf/d of natural gas and 109,000-122,000 bbls/d of oil and liquids.
- Talisman plans to participate in eight exploration and 25 development wells.



North Sea Production
(m boe/d)



United Kingdom Norway



Southeast Asia

Talisman is poised for continued strong production growth in Southeast Asia. The Company continues to develop its very large gas reserves in Indonesia and is actively negotiating new gas sales and transportation agreements. In Malaysia/Vietnam in 2003, Talisman completed its development project in the PM-3 Commercial Arrangement Area on time and on budget and made five new discoveries including South Angsi in Block PM-305.

Indonesia

In Indonesia, Talisman continues to develop its large gas reserves in the Corridor Block. Talisman's Corridor Block reserves have been independently evaluated. The Company is actively negotiating new gas sales contracts with the objective of doubling sales by 2007.

2003 in Review

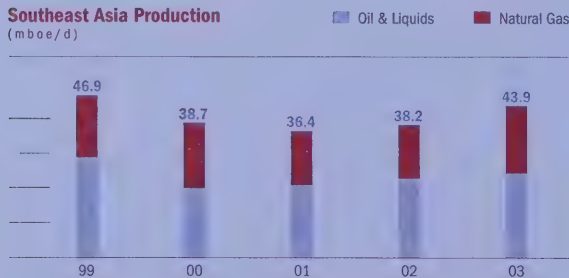
- Production averaged 112 mmcf/d of natural gas, an increase of 19% and 15,758 bbls/d of liquids.
- Exploration and development spending totaled \$41 million.
- Gas sales from Corridor to Singapore commenced on schedule in mid-September.
- Talisman entered into a new gas sales agreement to sell Corridor gas to Island Power in Singapore.
- A heads of agreement was signed and negotiations are underway to sell 2.4 tcf (Talisman 36%) of natural gas to West Java.
- Contracts are being finalized and pipeline tie ins are being prepared to sell 300 bcf of gas (Talisman 36%) to the island of Batam.

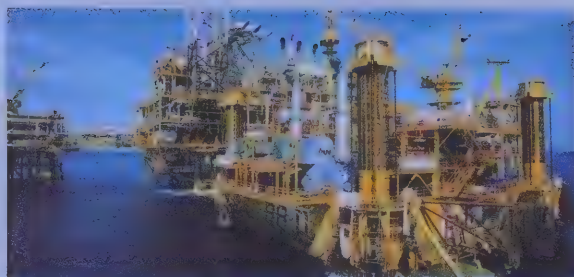
2004 Outlook

- Exploration and development spending is expected to be \$65 million, with \$12 million on exploration and \$53 million on development.
- Production targets are 135-140 mmcf/d of natural gas and 12,000-13,000 bbls/d of oil and liquids.
- The Suban Phase 2 project is expected to commence on completion of the West Java gas sales arrangements. The project involves installation of two new gas trains, additional pipelines and infrastructure in the Corridor PSC.



Southeast Asia Production
(mboe/d)





Malaysia/Vietnam

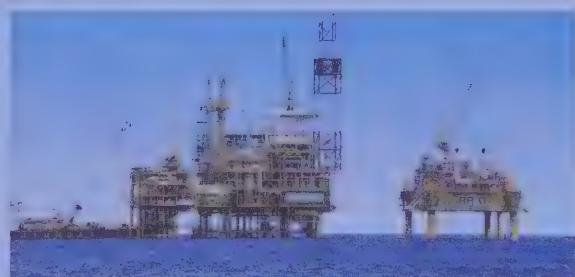
Talisman completed the \$1 billion PM-3 CAA Phase 2/3 oil and gas development project on time and on budget.

2003 in Review

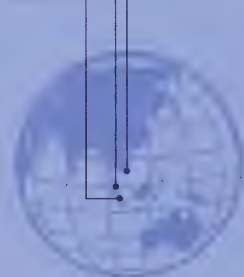
- First oil production from the PM-3 CAA Phase 2/3 oil and gas project commenced in September. Overall production averaged 9,502 boe/d for the year, with 19,427 boe/d in the fourth quarter.
- First natural gas production commenced in the fourth quarter.
- The Company had four successful discovery and appraisal wells on PM-3 CAA: North Bunga Orkid-1, East Bunga Orkid-2, North Bunga Pakma-2 and Bunga Tulip-1.
- Talisman made a significant oil discovery at South Angsi on Block PM-305 in Malaysia, which tested at 11,300 bbls/d. The South Angsi field development was sanctioned in late 2003 and first production is expected in mid-2005.
- Talisman discovered natural gas on Block 46-Cai Nuoc in Vietnam at the Hoa Mai exploration well, testing at 36 mmcf/d.
- Talisman made an oil discovery at Song Doc in Block 46/02 in Vietnam, which tested 7,300 bbls/d.
- Exploration and development spending totalled \$275 million.

2004 Outlook

- Exploration and development spending is expected to be \$250 million, with \$50 million on exploration and \$200 million on development.
- Production targets are 90-100 mmcf/d of natural gas and 21,000-25,000 bbls/d of oil and liquids.
- Talisman plans to drill five exploration and 32 development wells.
- Development of the South Angsi field will commence with first production expected in mid-2005.



Malaysia
Indonesia
Vietnam



The Caribbean and Latin America

Talisman is working in a number of high impact exploration areas, utilizing its expertise in structurally complex plays. In Trinidad, development of the Greater Angostura oil and gas project is underway. Talisman is continuing its exploration drilling programs in Trinidad and Colombia.

Trinidad and Tobago

Talisman has a 25% interest in the Greater Angostura project, a major oil and gas development in Block 2(c) offshore Trinidad. Field development is progressing, with first production anticipated in early 2005. Plans for 2004 include development drilling and the fabrication and installation of a central processing platform and three wellhead platforms. Further exploration and appraisal drilling is also planned for the southern portion of Block 2(c) where the Company holds a 35.7% interest.

Talisman also holds a 30% interest in Block 3(a), immediately east of Block 2(c). The Company drilled three exploration wells on Block 3(a) and one on Block 2(c) in 2003. All four wells encountered hydrocarbons, including the Punccheon-1 well on Block 3(a), which was drilling at year end.

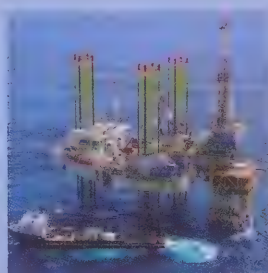
Talisman carried out a major 3D seismic acquisition program on the Eastern Block onshore Trinidad. The program will continue into 2004, with plans for the first exploration well in early 2005.

In Trinidad, the capital spending program is estimated to be \$170 million, which includes completion of the Angostura project, participation in 15 development and four exploration and appraisal wells and completion of onshore seismic operations.

Colombia

In Colombia, Talisman has non-operated interests in a number of blocks. During 2003, Talisman participated in two exploration wells. The El Encanto-2 well in the Huila Norte Block and the Candelo-1 well on the Acevedo Block both commenced drilling in September and were plugged and abandoned in early 2004. The exploration program in 2004 remains highly prospective with large potential targets.

Talisman's 2004 capital spending program in Colombia is expected to be \$28 million and includes seismic acquisition and drilling at least one additional exploration well.



Africa and the Middle East

Talisman has production and development interests in Algeria and exploration acreage in Qatar. The Company continues to evaluate new opportunities in this part of the world.

Algeria

During 2003, development of the first phase of the Greater MLN project located in Block 405a in eastern Algeria was completed, with production commencing in June. Talisman has a 35% non-operated interest in the block. In addition, the Company has a 2% interest in the unitized Ourhoud field, a small portion of which extends onto Block 405a. By the fourth quarter of 2003, Talisman's share of production was 11,804 bbls/d.

In 2004, Talisman plans capital spending of approximately \$44 million, which includes drilling 10 development wells at Ourhoud and six development wells in the Greater MLN area.

Talisman's share of production is expected to average between 14,000-16,000 bbls/d in 2004.

Qatar

In April 2003, Talisman received official ratification by the Emir of Qatar of an Exploration and Production Sharing Agreement entered into in late 2002 for offshore Block 10 (Talisman 100%). Geophysical work commenced in November and the Company plans to shoot 2D and 3D seismic in 2004.

Sudan

On March 12, 2003, Talisman completed the sale of its indirectly held interest in the Greater Nile Oil Project to ONGC Videsh Limited, a subsidiary of India's national oil company.

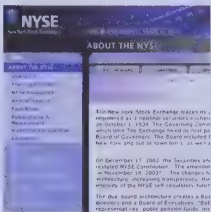


Talisman's corporate governance practices satisfy all the existing guidelines for effective corporate governance established by the Toronto Stock Exchange (TSX) and substantially all of the New York Stock Exchange (NYSE) corporate governance listing standards.

With the exception of the President and Chief Executive Officer, all directors have been determined by the Board to be "independent" within the meaning of the NYSE rules. Other than the Executive Committee of which only one member is a related, non-independent director, all of the Board committees are comprised of unrelated, independent directors. Each committee has a formal written mandate that addresses the purposes and responsibilities of the committee. Committee mandates can be found on Talisman's website at www.talisman-energy.com/aboutus/board_directors/corporate_governance.html.

In December 2003, Talisman revised its longstanding code of ethics to better reflect the evolving area of corporate responsibility and to incorporate the latest corporate governance requirements. The code, entitled the "Policy on Business Conduct and Ethics", can be obtained from Talisman's website at www.talisman-energy.com/socialresponsibility/business_conduct.html, or upon request from: Investor and Corporate Communications, Suite 3400, 888 Third Street SW, Calgary, Alberta T2P 5C5, or by email: tlm@talisman-energy.com.

A list of the existing TSX corporate governance guidelines is set out on the next page. Talisman complies with each guideline. A full description of Talisman's approach to corporate governance can be found in the Company's 2004 Management Proxy Circular.



TSX Corporate Governance Guidelines

The Board should explicitly assume responsibility for the stewardship of the Company and explicitly for:

- ✓ (a) adoption of a strategic planning process;
- ✓ (b) identification of the principal risks of the Company's business and ensuring implementation of appropriate systems to manage these risks;
- ✓ (c) succession planning, including appointing, training and monitoring senior management;
- ✓ (d) a communications policy, and
- ✓ (e) the integrity of the Company's internal controls and management information systems.
- ✓ A majority of the Company's directors should be unrelated.
- ✓ The Board has responsibility for applying to each individual director, the definition of "unrelated director" and disclosing on an annual basis the analysis of the application of the principles supporting this conclusion.
- ✓ The Board of every Company should appoint a committee of directors composed exclusively of outside, i.e., non-management directors, a majority of whom are unrelated directors, with the responsibility for proposing to the Board new nominees to the Board and for assessing directors on an ongoing basis.
- ✓ Every Board of Directors should implement a process to be carried out by the nominating committee or other appropriate committee, for assessing the effectiveness of the Board as a whole, its committees and the contribution of individual directors.
- ✓ The Company should provide an orientation and education program for new Board members.
- ✓ The Board should examine its size and undertake where appropriate, a program to reduce the number of directors to a number which facilitates more effective decision-making.
- ✓ The Board should review the adequacy and form of the compensation of directors and ensure the compensation realistically reflects the responsibilities and risk involved in being an effective director.
- ✓ Committees of the Board of Directors should generally be composed of outside directors, a majority of whom are unrelated directors, although some Board committees may include one or more inside directors.
- ✓ The Board should assume responsibility for, or assign to a committee of directors, the general responsibility for developing the Company's approach to governance issues. This committee would, amongst other things, be responsible for the Company's response to these governance guidelines.
- ✓ The Board, together with the CEO, should develop position descriptions for the Board and for the CEO, involving the definition of the limits to management's responsibilities. In addition, the Board should approve or develop the corporate objectives that the CEO is responsible for meeting.
- ✓ The Board of Directors should have in place appropriate structures and procedures to ensure that it can function independently of management. An appropriate structure would be to (i) appoint a chair of the Board who is not a member of management with responsibility to ensure the Board discharges its responsibilities or (ii) adopt alternate means such as assigning this responsibility to a committee of the Board or to a director, sometimes referred to as the "lead director". Appropriate procedures may involve the Board meeting on a regular basis without management present or may involve expressly assigning the responsibility for administering the Board's relationship to management to a committee of the Board.
- ✓ The Audit Committee should be composed only of outside directors. The roles and responsibilities of the Audit Committee should be specifically defined so as to provide appropriate guidance to Audit Committee members as to their duties. The Audit Committee should have a direct communication channel with the internal and external auditors to discuss and review specific issues as appropriate. The Audit Committee duties should include oversight responsibility for management reporting on internal controls. Although it is management's responsibility to design and implement an effective system of internal controls, it is the responsibility of the Audit Committee to ensure that management has done so.
- ✓ The Board should implement a system that enables an individual director to engage an outside adviser at the Company's expense in appropriate circumstances. The engagement of the outside advisor should be subject to the approval of an appropriate committee of the Board.

Corporate Responsibility

Talisman conducts its business worldwide according to applicable international laws and the high standards set out in its Policy on Business Conduct and Ethics.

There is a public expectation that, beyond profitability, companies must maintain high ethical, environmental and social standards. These standards have evolved over time, reflecting the changing values and priorities in society. Companies must enhance their efforts to publicly report on their standards and performance against these standards, to allow stakeholders to develop a more complete picture of companies' impact on society.

While Talisman strives to maximize shareholder value by conducting profitable operations in accordance with all applicable laws, our license to operate ultimately comes from the acceptance and goodwill of our stakeholders, including our employees, host governments and local communities. At Talisman, we operate in accordance with our Policy on Business Conduct and Ethics, which sets out our high standards in the areas of ethical business conduct, employee relations, environmental practices, human rights and community relations.

Some of Talisman's key accomplishments in 2003:

Social Performances:

- We completed a year-long review and update of our Policy on Business Conduct and Ethics, including the development of human rights and community relations principles for all Talisman employees and operations.
- We confirmed our participation in the Global Compact initiative led by the United Nations.
- We established formal security arrangements with our coventurers in Colombia in the spirit of the Voluntary Principles on Security and Human Rights.
- We worked with about 45,000 stakeholders, both individually and on a community-wide basis across Canada, to build awareness for the over 900 projects we were involved in.
- We developed formalized Aboriginal Relations Guidelines to help direct our relations with aboriginal communities across North America. We also established an Aboriginal Community Investment Fund.
- We established a community development legacy office in Sudan.
- We contributed approximately \$5 million to hundreds of community projects across our global operations.
- We contributed over \$663,000 to Calgary, Alberta's United Way, thanks to more than \$327,000 in employee donations, a corporate match of \$327,000 as well as numerous fundraising activities.

Talisman has published a separate Corporate Responsibility Report. You can view it on our website, or write, phone or email Talisman's main office in Calgary and we will be pleased to send you a copy.

Environmental Performance:

- We received a Certificate of Environmental Clearance in Trinidad with respect to our onshore exploration program.
- We began development of a cogeneration facility in Edson, Alberta and a potential offshore windfarm at our Beatrice platform in the North Sea.
- We completed environmental audits at our Canadian operations at Inga, Carlyle, Warburg and Grande Prairie and at all of our UK platforms and onshore terminals.
- We improved our Production Carbon Intensity by 5% from 2001 levels thanks to, among other things, gas conservation projects and reductions in venting.
- We decreased the overall concentration of oil in produced water discharged at all North Sea platforms by 18% to 20.4 parts per million in 2003.
- We achieved Gold Champion-Level Reporter status in the Voluntary Challenge and Registry (VCR) for our most recent submission (2002) to the VCR after two years at the Silver Level by reducing our current emissions or emissions intensity to levels below 1994 levels.
- During our first full year of operation of the Diamond Valley Soil Treatment Facility located near Turner Valley, Alberta, we treated approximately 10,000 tonnes of contaminated soil, which will be used as clean backfill in ongoing remediation projects in the area.





Management's Discussion and Analysis

(March 31, 2004)

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Piper Platform, North Sea

Highlights

(millions of Canadian dollars, unless otherwise stated)	2003	2002	2001
Cash flow ¹	2,729	2,645	2,494
Net income	1,007	524	733
Per share (Canadian dollars)			
Cash flow ¹	21.21	19.73	18.48
Net income	7.65	3.73	5.25
Dividends	0.70	0.60	0.60
Diluted per share (Canadian dollars)			
Cash flow ¹	20.95	19.43	18.15
Net income	7.57	3.67	5.16
Gross sales	5,295	5,299	5,047
Exploration and development spending	2,180	1,848	1,882
Total assets	11,365	11,594	10,819
Total long-term financial liabilities	2,203	2,997	2,794
Production (mboe/d)	398	445	419
Production per share (boe/share)	1.13	1.21	1.13
Average sales price (\$/boe)	37.67	32.10	32.91
Operating costs (\$/boe)	7.15	6.48	5.79
Proved reserves additions (before acquisitions and divestitures) (mmboe)	143	157	336
Finding and development costs ² (\$/boe)	14.28	11.03	5.34

1 Cash flow and cash flow per share are non-GAAP financial measures that represent net income before exploration costs, DD&A, future taxes and other non-cash expenses. The components of cash flow are set out in note 14 of the Consolidated Financial Statements. Cash flow for 2003 is cash provided by operating activities (\$2,616 million) before changes in non-cash working capital (\$104 million) and the deferred gain on unwound hedges (\$9 million). The equivalent amounts for 2002 are \$2,439 million, \$163 million and \$43 million, respectively. In 2001, the amounts are \$2,369 million, \$177 million less \$52 million for the deferred gain on the unwound hedges.

2 See the MD&A section entitled Reserves Replacement for method of calculation.

This Management's Discussion and Analysis (MD&A) dated March 3, 2004, should be read in conjunction with the Consolidated Financial Statements of the Company. In particular, note 18 provides segmented financial information that forms the basis for much of the following discussion and analysis. The Company's Consolidated Financial Statements and the financial data included in the MD&A have been prepared in accordance with accounting principles generally accepted in Canada. A summary of the difference between accounting principles generally accepted in Canada (Canadian GAAP) and those generally accepted in the United States (US) is contained in note 19 of the Consolidated Financial Statements.

Reported production represents Talisman's working interest share before royalties. Throughout the MD&A the calculation of barrels of oil equivalent (boe) is calculated at a conversion rate of six thousand cubic feet (mcf) of natural gas for one barrel of oil and is based on an energy equivalence conversion method. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalence conversion method primarily applicable at the burner tip and does not represent a value equivalence at the wellhead.

Dollar amounts included in the MD&A are expressed in Canadian dollars unless otherwise indicated. All comparative percentages are between the years ended December 31, 2003 and December 31, 2002, unless stated otherwise.

Included in the MD&A are references to financial measures commonly used in the oil and gas industry such as cash flow and cash flow per share. These financial measures have no standardized meaning and are not defined by accounting principles generally accepted in either Canada or the US. Consequently, these are referred to as non-GAAP measures. Cash flow, as commonly used, appears as a separate caption on the Company's cash flow statement and is reconciled to both net income and cash flow from operations. Cash flow is used by the Company to assess operating results between years and between peer companies with different accounting policies. Our reported amounts may not be comparable to similarly titled measures reported by other companies. Cash flow should not be considered an alternative to, or more meaningful than, cash provided by operating, investing and financing activities or net income as determined in accordance with Canadian GAAP as an indicator of the Company's performance or liquidity.

Additional information relating to the Company, including the Company's Annual Information Form, can be found on the Canadian System for Electronic Document Analysis and Retrieval (SEDAR) at www.sedar.com. The Company's annual report on Form 40-F may be found in the EDGAR database at www.sec.com.

Talisman's Performance Highlights in 2003

Talisman posted record cash flow per share of \$21.21 (\$2.7 billion) and exited 2003 with production of 437 mboe/d during December, replacing much of the production from the Sudan operations, which were sold in early 2003 for \$1.13 billion. Net income surpassed \$1 billion (\$7.65/share) for the first time in the Company's history, helped by high commodity prices, the gain on the Sudan disposition and tax rate reductions in Canada. During 2003, 3.3 million shares were repurchased at an average price of \$58.24/share, debt was reduced by \$794 million and the Company's semi-annual dividend rate increased 33% to \$0.40/share.

Operational highlights for the year included the startup of the PM-3 CAA development project in Malaysia/Vietnam, commencement of production in Algeria, first oil from Blake Flank in the North Sea and first natural gas sales from Indonesia to Singapore. A number of acquisitions were completed during 2003 for \$768 million including natural gas properties in the US, a producing field in Norway and midstream assets in Canada.

In Appalachia, Talisman drilled several successful exploration wells, adding significant productive capacity to the region. The North Sea saw three consecutive exploration successes, with discoveries at Tartan North, J5 and Affleck. In Malaysia and Vietnam, all exploration wells, except one, were either successful appraisals or new hydrocarbon discoveries. The Company also achieved good success in Trinidad with all four exploration wells discovering hydrocarbons.

Cash flow and cash flow per share increased for the fifth consecutive year to \$2.7 billion and \$21.21, respectively. This represents an 8% increase in cash flow per share over last year. Net income nearly doubled to \$1 billion (\$7.65/share) and included the gain on the Sudan sale (\$296 million or \$2.30/share) and tax rate reductions in Canada (\$160 million or \$1.24/share). These items were partially offset by an expense arising from amending the Company's stock option plans to include a cash payment feature, which resulted in what management believes to be more transparent accounting (\$185 million, \$130 million or \$1.01/share net of tax). Combined, these added \$326 million of net income (\$2.53/share).

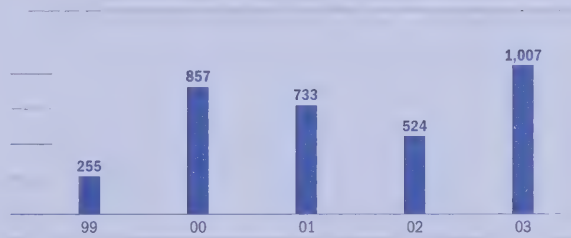
Production averaged 398 mboe/d for the year, within the target range originally set at the beginning of 2003. Production per share, after adjusting for the sale of the Sudan operations, increased 4%. Talisman spent \$2.2 billion on exploration and development activities and participated in drilling 651 successful wells in 2003. Excluding the impacts of the Sudan sale, 210 mmboe of proved plus probable reserves were added, replacing 150% of production.

Operating costs for 2003 were as expected and averaged \$7.15/boe, compared to \$6.48/boe in 2002.

Cash Flow
(millions of dollars)



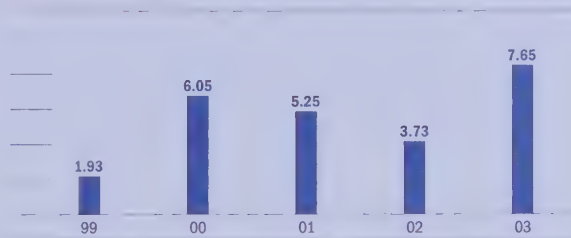
Net Income
(millions of dollars)



Cash Flow Per Share¹
(dollars)



Net Income Per Share
(dollars)



¹ Non-GAAP measure. See inside back cover.

2003 Variances

The significant variances from 2002 as summarized in the net income and cash flow variance table are:

- Higher commodity prices more than offset the impact of the sale of the Sudan operations, lower North Sea production, the strengthening of the Canadian dollar and higher royalties.
- Higher prices increased hedging losses.
- Interest expense fell due to lower average debt levels and lower effective borrowing costs, while current taxes fell primarily in the UK.
- Stock-based compensation payments reduced cash flow by \$47 million.
- The gain on the sale of the Sudan operations was \$296 million.
- The non-cash portion of the stock-based compensation expense reduced net income by \$138 million (before tax).
- Future taxes were lower in 2003 due to tax rate reductions in Canada. Future tax expense in 2002 included the impact of a tax rate increase in the UK.

2004 Outlook Summary

Talisman anticipates 4-12% production growth in 2004 from existing projects. Cash flow for 2004 is anticipated to be \$17-22 per share and assumes reduced commodity prices as expressed in Canadian dollars compared to 2003. Additional discussion of management's estimates and assumptions for 2004 can be found in the MD&A section entitled Outlook for 2004.

- Production is expected to average 415,000-445,000 boe/d.
- Production increases are expected in most of the Company's geographic segments with the majority coming from international projects.
- Exploration and development spending is expected to be \$2.35 billion (\$1.1 billion in North America and \$606 million in the North Sea).
- Significant progress on the Trinidad development is expected with first oil anticipated in early 2005.
- Average unit operating costs are expected to increase 5-10% reflecting an assumed strengthening of the UK pound sterling exchange rate against the Canadian dollar.
- Long-term debt is expected to increase partly due to the redemption of a portion of the Company's preferred securities.
- Stock-based compensation expense is expected to decrease, as 2003 included a catch-up charge due to amendments to the Company's stock option plans.

Net Income and Cash Flow Variance (millions of dollars)

2002 Net income	524
Favorable (unfavorable)	
Cash flow variance	
Sale of the Sudan operations	(281)
Oil and liquids volumes	(117)
Natural gas volumes	128
Natural gas prices	747
Oil and liquids prices	115
Hedging — Commodities	(270)
Royalties	(198)
Other revenue	8
Operating expense	(50)
Interest expense	27
Current taxes (including PRT)	(3)
General and administrative	(9)
Stock-based compensation payments	(47)
Other	34
Total cash flow variance	84
Non-cash items	
Sale of Sudan (including gain of \$296 million)	390
Depreciation, depletion and amortization expense	(21)
Dry hole expense	(90)
Exploration expense	(29)
Future taxes (including PRT)	219
Stock-based compensation (non-cash)	(138)
Other	68
Total non-cash items	399
2003 Net income ¹	1,007

¹ Net income, cash flow and cash flow per share are before preferred security charges of \$22 million, net of tax (\$38 million, before tax). Net income per share is after preferred security charges. The components of cash flow are set out in note 14 of the Consolidated Financial Statements.

Sale of Sudan Operations

On March 12, 2003, Talisman completed the sale of an indirectly held subsidiary, which owned an interest in the Greater Nile Oil Project in Sudan, to ONGC Videsh Limited ("OVL"), a subsidiary of India's national oil company. The aggregate amount realized by Talisman from the transaction (including interest and cash received by Talisman between September 1, 2002 and closing) was \$1.13 billion (US\$771 million). (See note 17 of the Consolidated Financial Statements.)

The following table has been provided to assist readers in understanding the Company's results after taking into account the sale of the Sudan operations. The pro forma amounts presented below exclude the \$296 million gain on sale of the Sudan operations and the Sudan results of operations during the respective years. These pro forma results have been derived from the information contained in notes 13 and 18 of the Company's December 31, 2003 Consolidated Financial Statements.

Pro Forma Results, Excluding the Sudan Operations and Gain On Sale

(millions of Canadian dollars, unless otherwise stated)

	Pro forma		
	2003	2002	2001
Cash flow	2,653	2,291	2,230
Net income	666	298	576
Per share (Canadian dollars)			
Cash flow	20.61	17.09	16.53
Net income	5.00	2.04	4.09
Diluted per share (Canadian dollars)			
Cash flow	20.37	16.82	16.23
Net income	4.94	2.01	4.02
Exploration and development expenditures	2,178	1,750	1,765
Production (daily average production)			
Oil and liquids (mbbls/d)	203.7	212.6	197.8
Natural gas (mmcf/d)	1,090	1,036	1,010
Total mboe/d (6mcf=1boe)	385	385	366

The pro forma amounts included in the above table do not include any adjustment for the assumed use of proceeds received on the sale of the Sudan operations.

Segmented Results Review

Talisman is an independent international upstream oil and gas company whose main business activities include exploration, development, production, transporting and marketing of crude oil, natural gas and natural gas liquids. The Company's operations in 2003 were conducted principally in four geographic segments: North America, the North Sea, Southeast Asia and Algeria. The Company is also participating in a significant development project in Trinidad. Exploration is being conducted in other areas outside the principal geographic segments including Colombia and Qatar. The Company's Sudan operations were sold on March 12, 2003. The following is a brief summary of the financial results of each geographic segment. Additional geographic financial results disclosure may be found in note 18 of the Consolidated Financial Statements. The Company's pre-tax segmented income as discussed below is before the gain on the sale of the Sudan operations, corporate general and administration, interest, stock-based compensation, taxes and non-segmented foreign exchange gains and losses. More detailed analysis on the Company's results can be found after this Segmented Results Review.

North America

During 2003, the North America operations contributed \$888 million or 56% of the Company's pre-tax segmented income of \$1.5 billion, up from \$437 million (31% of \$1.4 billion) in 2002. Gross sales in North America increased 34% to \$2.7 billion due principally to higher natural gas prices and production. North American production averaged 203,500

boe/d, up 2%, representing 51% of the Company's total production in 2003. North American operating expense increased 11% to \$395 million due to increased natural gas volumes, higher processing fees and higher power costs. DD&A increased to \$693 million, up from \$614 million due to higher production and recent acquisitions while dry hole expense increased to \$135 million due to the expanded exploration budget. Total exploration and development spending for North America in 2003 was \$1.1 billion, up 35% over 2002.

North Sea

The North Sea pre-tax segmented income decreased to \$435 million and accounted for 27% of the Company's segmented income during 2003, down from 38% in 2002. North Sea gross sales decreased due to lower liquids production, which also contributed to a lower DD&A expense. Production averaged 131,250 boe/d or 33% of the Company's total production. Royalty expense decreased due to the abolition of government royalties at the start of the year and the settlement of outstanding royalty issues. Dry hole expense increased with the inclusion of costs associated with the Eta-2 and Dunnottar wells. Exploration and development spending for the North Sea was \$496 million, up 15% from 2002.

Southeast Asia

Production from the PM-3 CAA development project in Malaysia/Vietnam started in 2003 with oil production commencing in September and natural gas in the fourth quarter. Southeast Asia contributed 12% (\$183 million) to the Company's pre-tax segmented income in 2003. Gross sales increased 14% to \$556 million with higher production from PM-3 CAA and Corridor in Indonesia. Southeast Asia production averaged 44,000 boe/d and contributed 11% to the Company's total production. Total operating expenses were unchanged from 2002, but unit costs were down 12% as a result of the 15% increase in production. DD&A expense increased with the growth in production. Capital spending for Southeast Asia was \$316 million, up 17%.

Algeria

Sales from Algeria commenced in January 2003 with the startup of the Ourhoud field. Production increased through 2003 with first oil from the Menzel Lejmat North (MLN) field in late June and additional production from MLN satellite fields in the fourth quarter. Production for 2003 averaged 6,600 bbls/d. Operating costs in 2003 included expenses associated with startup activities. Capital spending for Algeria was \$34 million, down 68% from 2002 due to the completion of the initial phase of the Greater MLN project.

Other Exploration and Development

Development continued on the Angostura oil and gas field located on Block 2(c) offshore Trinidad with the Company spending \$128 million during 2003. First production is expected in early 2005. Talisman spent \$21 million in Colombia on seismic and exploration drilling which commenced in the third quarter. Talisman also acquired a 100% interest in offshore Block 10 in Qatar with exploration drilling expected to commence in 2005.

Corporate Results Review

Revenue

Revenues from oil, liquids and natural gas sales in 2003 were \$5.3 billion, the same as in 2002. Higher natural gas prices (\$747 million), gas volumes (\$128 million) and oil prices (\$144 million) were offset by increased hedging losses (\$268 million) and lower oil and liquids volumes (\$766 million), primarily due to the sale of the Sudan operations.

Daily Production Volumes

	2003	2002	2001
Oil and liquids (mbbls/d)			
North America	59.6	62.7	66.0
North Sea	113.1	127.5	110.8
Southeast Asia	24.4	22.5	20.9
Algeria	6.6	—	—
Sudan	13.0	60.0	53.3
	216.7	272.7	251.0
Natural gas (mmcf/d)			
North America	864	820	809
North Sea	109	122	108
Southeast Asia	117	94	93
	1,090	1,036	1,010
Total (mboe/d @ 6:1)	398	445	419
Production per share (boe/share)	1.13	1.21	1.13

North America natural gas production increased 5% to 864 mmcf/d during 2003. This production growth is due to Talisman's successful drilling programs, the addition of infrastructure which helped alleviate production bottlenecks and strategic acquisitions. During 2003, Talisman drilled 625 wells in North America with a 93% success rate. The commissioning of the Erith pipeline and dehydration project and the acquisition of Vista Midstream will allow Talisman to continue to increase production in the Foothills and Deep Basin areas. At the end of 2002 and during the first quarter of 2003, Talisman purchased a number of high netback natural

gas properties in upper New York State. These properties added 60 mmcf/d during the year. However, production was constrained by access to infrastructure. This issue is being addressed. North America oil and liquids production averaged 59,578 bbls/d, down slightly from 2002 as the Company's North America exploration and development activities continue to focus on natural gas.

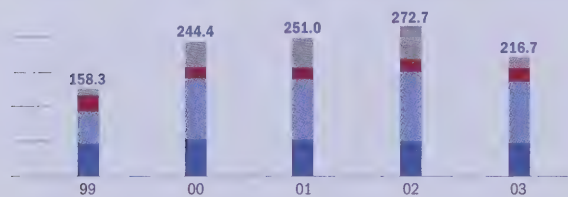
North Sea oil and liquids production averaged 113,075 bbls/d, down 11% from 2002, due primarily to natural decline. Production in the fourth quarter averaged 128,697 bbls/d, up 15% over the third quarter and 4% over the final quarter of 2002. North Sea production highlights for 2003 included the startup of the Blake Flank development, the acquisition of the Gyda field in Norway in the third quarter and the tie in of new wells at Halley, Hannay, Claymore and Braemar. The Ross/Blake core area, including Blake Flank, averaged 22,437 bbls/d during 2003, down from 2002 due to shutdowns to tie in Blake Flank and natural decline. Production from Gyda averaged 6,700 bbls/d in the fourth quarter. North Sea natural gas production decreased to 109 mmcf/d as 2002 production benefited from a temporary increase in access to export pipeline capacity at Brae.

Southeast Asia oil and liquids production increased 9% over 2002 to average 24,430 bbls/d in 2003. In the fourth quarter, production averaged 31,138 bbls/d, an increase of 39% over the final quarter of 2002. The PM-3 CAA development project came on stream at the end of September and increased total production in Malaysia/Vietnam to 22,738 bbls/d in December (32,506 boe/d including natural gas). Total Malaysia/Vietnam oil and liquids production for the year averaged 8,672 bbls/d. Indonesia oil and liquids production averaged 15,758 bbls/d, down slightly from 2002 due to natural decline.

Southeast Asia natural gas production increased 24% to 117 mmcf/d and exited 2003 with production of 196 mmcf/d in December. Natural gas production from the PM-3 CAA development project started in the fourth quarter and increased to 59 mmcf/d in December. First natural gas sales from Corridor in Indonesia to Singapore commenced in September under a 20 year contract with Gas Supply Pte Ltd. and averaged 13.5 mmcf/d during the fourth quarter. The majority of the remainder of the

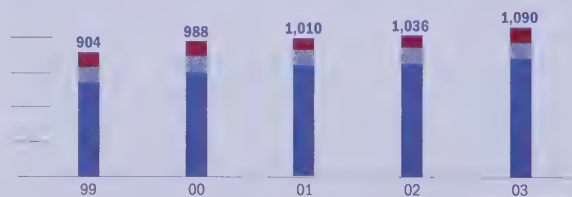
Oil and Liquids Production

(mbbls/d) ■ North America ■ North Sea ■ Southeast Asia ■ Algeria ■ Sudan



Natural Gas Production

(mmcf/d) ■ North America ■ North Sea ■ Southeast Asia



Indonesia natural gas production is sold to PT Caltex Pacific Indonesia (Caltex) under long-term variable demand contracts with minimum purchase requirements.

Algeria oil production for the year averaged 6,594 bbls/d and increased to 15,287 bbls/d during the month of December with the startup of the MLN satellite fields.

Commodity Prices

	2003	2002	2001
Oil and liquids (\$/bbl)			
North America	35.30	32.43	30.80
North Sea	39.72	38.76	36.07
Southeast Asia	41.05	39.46	35.97
Algeria	39.01	—	—
Sudan	43.89	37.79	32.66
	38.93	37.20	33.99
Natural gas (\$/mcf)			
North America	6.37	3.96	5.39
North Sea	4.57	3.89	4.35
Southeast Asia	4.95	4.72	4.80
	6.03	4.03	5.22
Company \$/boe (6 mcf=1 boe)	37.67	32.10	32.91
Hedging loss (income) excluded from the above prices			
Oil and liquids (\$/bbl)	2.05	0.09	(0.16)
Natural gas (\$/mcf)	0.08	(0.22)	0.02
Total \$/boe (6mcf=1boe)	1.34	(0.46)	(0.05)
Benchmark prices			
WTI (US\$/bbl)	30.99	26.15	25.92
Dated Brent (US\$/bbl)	28.83	25.03	24.46
NYMEX (US\$/mmbtu)	5.44	3.25	4.38
AECO (C\$/gj)	6.35	3.86	5.97

Prices are before hedging activities and do not include synthetic oil.

World oil prices increased in 2003 over 2002 with WTI averaging US \$30.99, up 19%. North American natural gas prices also increased considerably over 2002 with NYMEX averaging US\$5.44/mmbtu, up 67%.

More than 90% of the Company's revenues are either received in US dollars or are closely referenced to US dollars. The Company converts these revenues to Canadian dollars for reporting purposes. The strengthening of the Canadian dollar reduced Talisman's reported oil and liquids price by \$4.71/bbl. Talisman's North America oil and liquids price averaged \$35.30/bbl, up 9% from last year. The Company's North Sea oil price averaged \$39.72/bbl, up 2% over 2002. The Company's Southeast Asia oil price averaged \$41.05/bbl, up 4% over 2002.

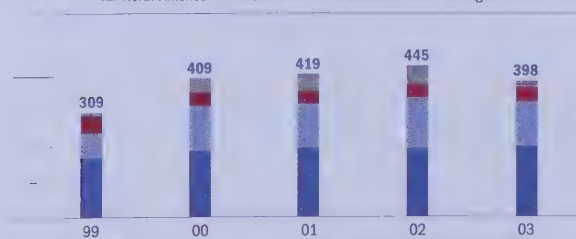
Talisman's average natural gas price in North America increased 61% to \$6.37/mcf. The strengthening of the Canadian dollar during 2003 reduced Talisman's reported North America natural gas price by \$0.70/mcf. The Company's North Sea natural gas price increased 17% as a result of a higher proportion of the gas being sold under long-term contracts.

The Company's natural gas price in Southeast Asia averaged \$4.95/mcf, up 5% from 2002. A majority of Corridor gas production, which constituted approximately 90% of the Company's 2003 gas sales in Southeast Asia, is exchanged for Duri crude oil on an energy equivalent relationship and is sold offshore with payment in US dollars. The majority of the Company's other natural gas sales in Southeast Asia are referenced to Singapore fuel oil spot market prices. A 2002 adjustment to Corridor's gas price, relating to 2001, decreased Talisman's average Southeast Asia reported gas price in 2002 by \$0.22/mcf.

The Company's average sales prices are before a net hedging loss of \$194 million, comprised of a \$0.08/mcf loss on gas hedges (2002 — \$0.22/mcf gain) and a \$2.05/bbl loss on oil hedges (2002 — \$0.09/bbl loss). The physical and financial commodity price contracts for 2004 outstanding at year end are disclosed in notes 9 and 10 of the Consolidated Financial Statements with additional discussion in the MD&A section entitled Derivative Financial Instruments and Commodity Sales Contracts. Additional discussion of the expected impact of commodity price contracts on the Company's 2004 results can be found in the Outlook for 2004 section of this MD&A. The Company's accounting policy with respect to derivative financial instruments and commodity contracts is disclosed in note 1(k) of the Consolidated Financial Statements.

Total Production

(m boe/d) North America North Sea Southeast Asia Algeria Sudan



Royalties

	2003		2002		2001	
	Rates (%)	\$millions	Rates (%)	\$millions	Rates (%)	\$millions
Oil and liquids						
North America	21	155	21	149	22	164
North Sea	—	(3)	4	74	5	75
Southeast Asia	39	143	38	122	30	82
Algeria	49	46	—	—	—	—
Sudan	46	97	40	328	39	248
	14	438	18	673	18	569
Natural gas						
North America	22	432	19	224	25	394
North Sea	6	11	12	21	11	18
Southeast Asia	6	13	5	9	5	8
	19	456	17	254	22	420
	16	894	18	927	20	989

Royalty rates do not include synthetic oil.

The consolidated royalty expense decreased to \$894 million in 2003, with the sale of the Sudan operations accounting for most of the drop. In addition, effective January 1, 2003, the UK abolished government royalties. Agreement was also reached on various outstanding UK royalties issues in respect of prior years, which also reduced the North Sea royalty expense for 2003. North Sea royalties are expected to average 2% during 2004 due to non-government royalty interests.

Talisman's North America natural gas royalties, which are largely determined on a sliding scale based on price, averaged 22%, up from 19% in 2002. The royalty rate in 2003 on North America natural gas production did not reach the rate incurred during 2001, when prices were at similar highs due to increased production being sourced from lower royalty rate regions such as the Company's Appalachia production, which had a royalty rate of 14% in 2003.

The Company's royalty rate for oil and liquids decreased, year-over-year, to 14% due to the reduction in the North Sea and the sale of the Sudan operations. Without Sudan, the Corporate royalty rate for oil and liquids would have been 12% in 2003 (2002 — 12%; 2001 — 13%). Southeast Asia oil and liquids royalties averaged 39% in 2003 and 2002 primarily due to the depletion of a cost recovery pool at Tanjung during 2002. Oil from PM-3 CAA in Malaysia/Vietnam has a current royalty rate of 30%, while natural gas sales have a royalty rate of 25%.

Corridor's natural gas royalty rate averaged 5% during 2003, consistent with prior years; however, the royalty rate is expected to increase to approximately 22% in 2004 and 30% in 2005.

Under the terms of the Algerian production sharing contractual arrangement, Talisman is subject to a 51% royalty rate during the first five years of production. During the first four years of production, Talisman receives accelerated production entitlement. At the end of year five, any accelerated production entitlement received by Talisman during the first four

years in excess of 49% on a cumulative basis reverts to the government. Accordingly, during the first four years of production, Talisman will record a deferred royalty expense and liability for any production entitlement received in excess of 49%. During 2003, Talisman recorded deferred Algerian royalties of \$14 million.

Operating Expenses and Unit Operating Costs

	2003		2002		2001	
	\$/bbl	\$millions	\$/bbl	\$millions	\$/bbl	\$millions
Oil and liquids						
North America	6.28	131	5.55	121	5.22	121
North Sea	12.67	523	11.11	517	10.06	407
Southeast Asia	7.33	65	7.93	65	7.13	54
Algeria	6.84	16	—	—	—	—
Sudan	3.73	18	3.82	84	3.40	66
	9.63	753	7.99	787	7.15	648
Natural gas	\$/mcf	\$millions	\$/mcf	\$millions	\$/mcf	\$millions
North America	0.75	237	0.71	212	0.67	198
North Sea	0.54	21	0.61	27	0.46	18
Southeast Asia	0.50	22	0.59	21	0.47	16
	0.70	280	0.69	260	0.63	232
Company (boe)	7.15	1,033	6.48	1,047	5.79	880
Synthetic oil	22.63	22	18.00	19	20.05	20
Pipeline	—	44	—	49	—	46
	—	1,099	—	1,115	—	946

Total operating expenses for the Company were \$1.1 billion. The reduction due to the sale of the Sudan operations was largely offset by higher natural gas operating expenses in North America due to increased volumes and higher processing and power costs and the startup of Algeria. On a unit basis, oil and liquids costs increased to \$9.63/bbl due to the sale of the Sudan operations and lower North Sea volumes.

Oil and liquids unit operating costs in North America during 2003 increased to \$6.28/bbl, largely due to lower production and higher power costs. Unit operating costs for natural gas increased to \$0.75/mcf with higher processing and power costs partially offset by the lower unit operating costs (\$0.18/mcf) in Appalachia.

In 2003, North Sea oil and liquids operating expenses of \$523 million in part reflected the weaker pound sterling. However, unit costs averaged \$12.67/bbl on lower volumes. The UK pound sterling strengthened against the Canadian dollar during 2002 and accounted for over half of the unit cost increase in 2002 over 2001, with the remainder due to higher maintenance and well workover costs.

Southeast Asia unit operating costs decreased 12% to \$5.41/boe due to higher sales volumes at Corridor and the startup of the PM-3 CAA development project. The strengthening of the Canadian dollar against the US dollar helped keep total operating expenses flat compared to 2002. Oil and liquids unit costs averaged \$7.33/bbl with PM-3 CAA averaging

\$6.14/bbl and the Indonesia blocks averaging \$7.98/bbl. Natural gas unit costs averaged \$0.51/mcf at Corridor, down from 2002 on higher volumes.

Algeria unit operating costs averaged \$6.84/bbl and included costs associated with startup activities.

Depreciation, Depletion and Amortization Expense

	2003		2002		2001	
	\$/boe	\$millions	\$/boe	\$millions	\$/boe	\$millions
North America	9.33	693	8.44	614	7.98	585
North Sea	12.91	619	12.99	701	11.86	558
Southeast Asia	5.92	95	6.24	87	7.00	93
Algeria	6.99	17	—	—	—	—
Sudan	3.98	19	4.24	93	3.98	77
	9.92	1,443	9.19	1,495	8.58	1,313

The Company's depreciation, depletion and amortization (DD&A) expense decreased \$52 million to \$1.4 billion due to the sale of the Sudan operations but was up on a unit basis to \$9.92/boe. The DD&A rate in North America increased with recent acquisitions including the US property acquisitions at the end of 2002 and the beginning of 2003, Petromet in 2001 and Vista Midstream in 2003. In the North Sea, the DD&A rate decreased \$0.08/boe. The Southeast Asia rate decreased to \$5.92/boe due in part to the strengthening Canadian dollar and higher Corridor production.

For additional information relating to DD&A refer to the MD&A section entitled Application of Critical Accounting Policies and to note 4 of the Consolidated Financial Statements.

Dry Hole Expense

(millions of dollars)	2003	2002	2001
North America	135	128	54
North Sea	69	9	21
Southeast Asia	9	4	8
Algeria	1	—	5
Sudan	—	13	16
Other ¹	37	20	9
	251	174	113

¹ Other includes Trinidad, Colombia and frontier North America.

A high risk exploration well offshore Nova Scotia and the Eta-2 and Dunnotar wells in the North Sea contributed to the increase in dry hole expense in 2003. The increase in North America reflects increased drilling during 2003. The Company wrote off two wells in Colombia, two in Indonesia and one in Malaysia. Under the Successful Efforts method of accounting for oil and gas activities, the costs of unsuccessful exploration wells are written off to dry hole expense in the year such determination is made. Until such determination is made, the costs are included in non-depleted capital. At year end, \$283 million of costs relating to exploration wells (2002 — \$353 million; 2001 — \$399 million), were included in non-depleted capital and not subject to DD&A pending final determination.

Exploration Expense

(millions of dollars)	2003	2002	2001
North America	87	66	69
North Sea	21	20	30
Southeast Asia	17	19	8
Algeria	—	5	2
Sudan	5	6	11
Other	83	69	27
	213	185	147

Exploration expense consists of geological and geophysical costs, seismic, land lease rentals and indirect exploration expenses. These costs are expensed as incurred under Successful Efforts accounting.

There has been a steady increase in the Company's exploration spending since 1999. Exploration expense is closely tied to the total amount of exploration capital spent in a year. Expenses constituting "Other" in 2003 and 2002 relate mostly to activities in Trinidad, East Coast offshore North America and Colombia.

Corporate

(millions of dollars)	2003	2002	2001
G&A expense	152	138	108
Interest expense	137	164	139
Capitalized interest	24	25	19
Stock-based compensation	185	—	—
Preferred securities charges, net of tax	22	24	24
Other revenue	76	80	82
Other expense	16	113	78

General and administrative (G&A) expense increased due to additional documentation requirements associated with recently implemented corporate governance initiatives, higher legal and pension costs, salary increases and additional personnel due to expanding investment and operations. On a unit basis, G&A was \$1.05/boe and increased in part due to lower oil and liquids production (2002 — \$0.85/boe; 2001 — \$0.71/boe).

As a result of lower average debt levels and lower effective interest rates during the year, interest on long-term debt, including capitalized interest, decreased to \$161 million. Interest capitalized over the last three years is primarily associated with the Malaysia/Vietnam PM-3 CAA development, which came on production during 2003. Capitalized interest in 2003 also included interest associated with the Angostura development in Trinidad.

Preferred securities charges, net of taxes, of \$22 million have been charged directly to retained earnings and are deducted from net income to determine net income per share. Preferred security charges, before tax, totalled \$38 million.

Other revenue includes pipeline and custom treating revenues and miscellaneous income. Other expense for 2003 included foreign exchange losses of \$7 million and property impairment in the North

Sea of \$30 million due to unsuccessful development drilling at Ivanhoe and was partially offset by gains on property dispositions of \$14 million. Other expense for 2002 included the Kildrummy and Beechnut write-offs (\$74 million), foreign exchange losses (\$28 million) and losses on property dispositions (\$10 million).

Stock-Based Compensation

The Company's stock option plans were amended during 2003 to provide employees and directors who hold stock options with the choice upon exercise to purchase a share of the Company at the stated exercise price or to receive a cash payment in exchange for surrendering the option. The cash payment is equal to the appreciated value of the stock option as determined based on the difference between the option's exercise price and the Company's share price at the time of surrender. The cash payment alternative is expected to result in reduced shareholder dilution in the future as it is anticipated that most holders of the stock options (now and in the future) will elect to take a cash payment. Such cash payments made by the Company to stock option holders are deductible by the Company for income tax purposes, making these plans more cost effective.

As a result of the Company's decision to start expensing stock options, the Company's second quarter results included a \$105 million (\$74 million, or \$0.57/share, net of tax) stock-based compensation expense relating to the appreciated value of the Company's outstanding stock options and cash units at June 30, 2003. The total stock-based compensation expense for the year was \$185 million (\$130 million, net of tax) including \$80 million during the second half of 2003 due to the appreciation of the Company's stock price during the period July 1 to December 31. Additional stock-based compensation expense or recoveries in future periods is dependent on the movement of the Company's share price and the number of outstanding options and cash units.

Income Taxes

The Company's effective tax rate for 2003, after deducting Production Revenue Tax (PRT), was 15% compared to 44% in 2002 and 36% in 2001. A number of events in the past two years have significantly impacted the Company's effective tax rates including the 2003 tax rate reductions in Canada, the sale of the Sudan operations and a supplemental oil and gas tax enacted in the UK in 2002.

Effective Income Tax Rate

(millions of dollars)	2003	2002	2001
Income before tax	1,277	1,068	1,296
Less PRT	92	124	149
	1,185	944	1,147
Income tax expense (recovery)			
Current	229	258	342
Future	(51)	162	72
	178	420	414
Effective income tax rate (%)	15	44	36

In 2003, the Company recorded a future tax recovery of \$160 million due to a reduction in Canadian federal and provincial tax rates. A similar rate reduction in the Alberta corporate tax rate in 2002 resulted in a future tax recovery of \$12 million. Effective April 17, 2002, the UK increased its corporate income tax rate applicable to North Sea oil and gas profits by enacting a 10% supplementary charge. This increased the Company's future tax expense for 2002 by \$128 million. Partially offsetting this tax increase was the acceleration of tax allowances for capital expenditures incurred after April 17, 2002.

A normalized effective tax rate after removing the impact of the Canadian and UK tax rate changes and the impact of the gain on disposal of the Sudan operations would have been 38% in 2003, 32% in 2002 and 36% in 2001. See note 13 of the Consolidated Financial Statements for additional information on the Company's income taxes.

Current income tax expense decreased to \$229 million in 2003, primarily due to the sale of the Sudan operations. An increase in current taxes in Canada due to higher natural gas prices was partially offset by lower current taxes in the North Sea.

The UK Government levies PRT on North Sea fields which received development approval before April 1993, based on gross profit after deducting allowable expenditures, a cost uplift, a portion of losses from certain other fields, abandonment costs and government royalties. PRT is deductible for purposes of calculating corporate income tax.

Capital Spending

(millions of dollars)	2003	2002	2001
North America	1,580	939	976
North Sea	693	518	664
Southeast Asia	316	269	149
Algeria	34	107	63
Sudan	2	98	117
Other	223	121	52
Non-segmented	38	26	30
	2,886	2,078	2,051

Includes exploration, development and net asset acquisitions expenditures but excludes the Sudan disposition in 2003 and the Lundin and Petromet acquisitions in 2001.

Natural gas continues to be the focus of the Company's capital investment activities in North America, supplemented by low risk oil projects and strategic acquisitions. Of the \$1.6 billion of capital spending in North America, \$453 million related to exploration activities while development accounted for \$656 million. The Company participated in 378 gas wells and 204 oil wells in North America and had a success rate of 93%. Development spending was concentrated in the predominantly gas producing core area in the Alberta Foothills, Greater Arch, Deep Basin, Monkman and Edson area and included the Erith pipeline and dehydration project which was commissioned in the fourth quarter. In addition, the Company spent \$471 million on acquisitions, net of dispositions, including US properties (\$385 million) and Vista Midstream Solutions Ltd. (\$130

million). The Company's US properties located in New York State, including those purchased at the end of 2002, contributed 60 mmcf/d of production during 2003. The Vista acquisition provides Talisman access to infrastructure and midstream revenues in the Deep Basin area of Alberta, one of Talisman's key natural gas growth areas.

Total capital spending in the North Sea of \$693 million included \$99 million for exploration and \$397 million for development with the remaining \$197 million for net property acquisitions. Development expenditures included Blake Flank and drilling within the Clyde, Buchan, Ross, Tartan and Claymore core areas. A total of 14 successful development wells were drilled during 2003 in the North Sea. Exploration drilling included the successful Tartan North, J5 and Affleck (Clyde) exploration wells. The Eta-2 and Dunnottar exploration wells were written off to dry hole expense. During 2003, the Company completed the purchase of a 61% operating interest in the Norwegian offshore Gyda field, associated facilities and adjacent acreage for \$112 million, including \$21 million of assumed working capital deficiency. Goodwill of \$31 million was recorded related to this acquisition. The Company also acquired additional minor working interests in eight North Sea fields and exploration blocks.

The PM-3 CAA development in Malaysia/Vietnam accounted for a majority of the \$316 million (including \$22 million of capitalized interest) of total capital spending in Southeast Asia. Talisman participated in drilling 21 successful development wells in Malaysia/Vietnam during 2003. In addition, two successful exploration wells were drilled in PM-3 CAA and one in each of Block PM 305, Block 46-Cai Nuoc and Block 46/02. A total of \$41 million was spent in Indonesia with over half going to develop Corridor in order to support gas sales to Singapore and possible future sales to West Java. Talisman participated in drilling seven successful oil and gas wells in Indonesia during 2003.

Capital spending in Algeria totaled \$34 million in 2003 and the Company participated in 12 successful wells during the year.

Other areas accounted for \$223 million of the 2003 capital spending. Talisman spent \$130 million in Trinidad to advance the Angostura development on offshore Block 2(c) with first oil anticipated in early 2005. Four exploration wells were drilled offshore Trinidad during 2003 and all four encountered hydrocarbons, including the one drilling over year end. The Company spent \$21 million in Colombia on seismic and to participate in drilling two exploration wells, which were drilling at year end but have subsequently been abandoned.

Reserves Replacement

Talisman drilled 651 successful wells in 2003, adding 143 mmbœ of proved reserves and replacing 99% of conventional production at a cost of \$14.28/bœ before acquisitions and dispositions. The Company's total proved reserves decreased 8% to 1,362 mmbœ, primarily due to the sale of the Sudan operations (156 mmbœ). Excluding the impacts of the Sudan sale, both proved and probable reserves increased by approximately 3% each and, in total, production replacement from

all sources (including proved and probable discoveries, revisions and net acquisitions excluding Sudan) was 150%.

Over the last three years, the Company has replaced approximately 139% of production before acquisitions and divestitures at a cost of \$8.76/bœ on a proved reserves basis. Net revisions and transfers over the past three years, which are included in the above replacement rate, have resulted in a cumulative reduction of 8 mmbœ or less than 1% of the Company's proved reserves.

Finding, Development and Acquisition Costs (gross before royalties)

Proved F&D costs (\$/bœ)	2003	2002	2001	3-year Average	5-year Average
F&D ¹	14.28	11.03	5.34	8.76	7.89
FD&A ² (excluding Sudan sale ³)	14.67	12.15	7.08	9.79	8.64

- F&D costs have been calculated by dividing finding and development costs (excluding net acquisition costs), as reconciled in the table below, by proved gross before royalties reserves additions including revisions but excluding net acquired proved gross before royalties reserves.
- FD&A costs have been calculated by dividing finding and development costs (including net acquisition costs), as reconciled in the table below, by proved gross before royalties reserves additions including revisions and net acquired proved gross before royalties reserves.
- FD&A including the impacts of the Sudan sale for 2003 is \$72.84/bœ.

The finding and development costs have been calculated based on current year's exploration and development spending excluding synthetic oil operations capital, midstream expenditures, indirect exploration costs, enhanced oil recovery and capitalized interest divided by current year proved reserves additions. No amount of future capital has been included in the above calculation, which is consistent with calculations performed in prior years. The costs used in the above calculation has been reconciled to exploration and development expenditures as set out in the notes to the Consolidated Financial Statements.

Reconciliation of Costs Included in F&D Calculations

(gross before royalties)

(millions of dollars)	2003	2002	2001
Exploration and development expenditures	2,180	1,848	1,882
Less:			
Midstream capital	27	21	27
Indirect costs	52	41	34
Capitalized interest	24	25	19
Synthetic oil operations capital	30	24	8
Enhanced recovery expenditures	4	2	2
	2,043	1,735	1,792

The following finding and development costs have been calculated in US dollars in a manner consistent with US practice which is calculated based on current additions to proved reserves net after royalties. Costs used in the US\$/bœ, net of royalties F&D calculations have been reconciled in the table below to the property acquisition, exploration and development costs as set out in the Supplementary Oil and Gas Information under the heading Costs Incurred in Oil and Gas Activities.

Finding, Development and Acquisition Costs (net after royalties)

US\$/boe				3-year	5-year
Proved F&D costs, net	2003	2002	2001	Average	Average
F&D ¹ , net	11.71	11.80	4.40	7.72	7.33
FD&A ² , net (excluding Sudan sale)	12.12	12.24	6.04	8.62	7.76

- 1 F&D net costs have been calculated by dividing finding and development costs (excluding acquisition costs) in US dollars, as reconciled in the table below, by proved net after royalties reserves additions including revisions but excluding acquired proved net after royalties reserves.
- 2 FD&A net costs have been calculated by dividing finding and development costs (including acquisition costs) in US dollars, as reconciled in the table below, by proved net after royalties reserves additions including revisions and acquired proved net after royalties reserves.

Reconciliation of Costs Included in F&D Calculations (net of royalties)

US\$ millions	2003	2002	2001
Exploration and development costs (FAS 69)	1,430	1,111	1,152
Less: Capitalized interest	(17)	(16)	(12)
Exploration and development costs	1,413	1,095	1,140
Acquisition costs (FAS 69)	533	212	1,080
Total exploration, development and acquisition costs	1,946	1,307	2,220

Liquidity and Capital Resources

Talisman's long-term debt at year end was \$2.2 billion (\$2.1 billion, net of cash and cash equivalents), down from \$3 billion at the end of last year. At year end, the Company had not drawn on any of its available \$1,135 million bank lines of credit. The Company maintains a shelf prospectus under which it may issue up to \$500 million of medium term notes in aggregate in the Canadian public debt market. The shelf prospectus expires in April 2004. In December 2003, the Company filed a debt shelf prospectus in the US under the Multi-jurisdictional Disclosure System (MJDs) under which it may issue up to US\$1 billion of debt securities in the US public debt market.

In 2003, the Company received approximately \$1 billion in net proceeds from the sale of its Sudan operations. Use of these proceeds to repay debt accounted for the majority of the decrease in long-term debt during the year, along with the impact of a stronger Canadian dollar on US dollar denominated debt, which reduced long-term debt by \$349 million. The Company generated \$2.7 billion of cash flow and spent \$2.2 billion on exploration and development and a net \$600 million on acquisitions.

In 2004, \$107 million (\$75 million and US\$25 million) of long-term debt matures and will be repaid. None of the long-term debt has been classified as a current liability as the Company has the ability and intention to refinance amounts due within one year with existing bank facilities. At year end, the Company had outstanding two issues of preferred securities totaling US\$300 million. The preferred securities are carried on the Company's balance sheet as equity at \$431 million, which is based on the historical exchange rate at the time of their issuance. These securities are callable, in whole or in part, at par by Talisman starting in 2004. Subsequent to year end, the Company redeemed

US\$150 million of these securities. The difference between the carrying value of the redeemed preferred securities (\$215 million) and the cost of redemption (\$197 million) will be credited directly to retained earnings.

The Company repurchased 3,335,600 of its common shares under its normal course issuer bid (NCIB) during 2003 for a total of \$194 million (\$58.24/share). The NCIB expires in March 2004 and is expected to be renewed, which will allow the Company to repurchase up to 5% of the Company's outstanding common shares.

Two common share dividends were paid in 2003 (total dividends were \$0.70/share). The Company's dividend is determined semi-annually by the Board of Directors. Commencing with the December 2003 payment, the semi-annual dividend was increased to \$0.40/share (\$0.80/share annually). At year end, there were 128 million common shares outstanding.

Talisman targets long-term debt of less than 2:1 on a debt to cash flow basis and 45% on a debt to debt-plus-equity basis. These targets incorporate the debt refinancing of the Company's preferred securities during 2004. At the end of 2003, Talisman met the debt targets with ratios of 0.8:1 for debt to cash flow and 31% for debt to debt-plus-equity. For purposes of these calculations the Company's preferred securities have been classified as equity.

For additional information regarding the Company's liquidity and capital resources, refer to note 5 of the Consolidated Financial Statements. In addition, refer to the Sensitivities table included in the Outlook Section of this MD&A for possible 2004 impacts of various factors on the Company's estimated 2004 net income and cash flows.

Talisman's investment grade corporate credit and senior unsecured long-term debt credit ratings remain unchanged with Dominion Bond Rating Service ("DBRS"), Moody's Investor Service, Inc. ("Moody's") and Standard & Poor's ("S&P") at BBB (high), Baa1 and BBB+ respectively. Due to the subordinated nature of the preferred securities, they have a lower rating. DBRS, Moody's and S&P have rated the preferred securities as Pfd-3(high), Baa3 and BBB-, respectively.

Commitments and Off Balance Sheet Arrangements

As part of its normal business, the Company has entered into arrangements and incurred obligations that will impact the Company's future operations and liquidity, some of which are reflected as liabilities in the Consolidated Financial Statements at year end. The principal commitments of the Company are in the form of: debt repayments; abandonment obligations; settlements of derivative financial instruments; lease commitments relating to corporate offices and ocean-going vessels; firm commitments for gathering, processing and transmission services; minimum work commitments under various international agreements; other service contracts; and fixed price commodity sales contracts.

Additional disclosure of the Company's debt repayment obligations and significant commitments can be found in notes 5 and 10 of the Consolidated Financial Statements. A discussion of the Company's derivative financial instruments and commodity sales contracts can be found in the next section of this MD&A.

Derivative Financial Instruments and Commodity Sales Contracts

The Company may manage its exposure to fluctuations in foreign exchange rates, interest rates, electricity costs and commodity prices in part through the use of derivative financial instruments and commodity sales contracts. The accounting policy with respect to derivative financial instruments is set out in note 1(k) of the Consolidated Financial Statements. Derivative financial instruments outstanding at December 31, 2003, including their respective fair values, are detailed in note 9 of the Consolidated Financial Statements.

During 2003, the Company's commodity price derivative financial instruments resulted in a net decrease to recorded sales of \$194 million (2002 – \$75 million increase; 2001 – \$8 million increase). At December 31, 2003, the Company had outstanding commodity price derivative contracts that cover approximately 55 mmcf/d (6%) of the Company's anticipated 2004 North American natural gas production and 79,000 bbls/d (37%) of the Company's anticipated 2004 worldwide oil and liquids production. An additional 56 mmcf/d (6%) of anticipated 2004 North American natural gas production has been committed under fixed price and three-way collar commodity sales contracts. See notes 9 and 10 of the Consolidated Financial Statements for additional details regarding the contracts outstanding at year end.

In order to support the Company's investments in natural gas projects outside North America and the North Sea, Talisman has entered into a number of long-term sales contracts. In conjunction with the PM-3 CAA development project the Company has entered into a long-term firm supply contract for approximately 100 mmcf/d at prices referenced to the Singapore fuel oil spot market. Natural gas production from the development commenced during the fourth quarter. The majority of Talisman's Corridor natural gas production in Indonesia is sold to Caltex under long-term sales agreements and is exchanged for crude oil on an energy equivalent relationship. The crude oil received from Caltex is then sold offshore. Sales to Singapore from Corridor are also under long-term sales agreements referenced to the spot price of fuel oil in Singapore. The Company anticipates having sufficient production to meet all future delivery commitments.

During 2003, the Company had £250 million of US dollar cross currency swap contracts and interest rate swap contracts outstanding. These contracts were designated as hedges of the £250 million Eurobond, which in effect converted this indebtedness into US dollars with a floating interest rate based on three month US LIBOR. The cross currency and interest rate swap contracts reduced the Company's 2003 interest expense by \$27 million (2002 – \$15 million) and the year end Canadian dollar reported debt by \$106 million. As discussed in the MD&A section entitled Change in Accounting Policies, effective

The following table includes the Company's expected future payment commitments and estimated timing of such payments.

			Payments expected ^{1,2} (millions of dollars)					
Commitments	Recognized in financial statements	Total	Due within 1 year	Due within 2-3 years	Due within 4-5 years	Due within 6-10 years	Due within 11-15 years	Due after 15 years
Long-term debt	Yes – Liability	2,203	107	271	766	200	471	388
Abandonment obligations ³	Yes – Partially accrued as liability	2,018	9	34	92	373	552	958
Preferred securities ⁴	Yes – Equity	388	194	—	—	—	—	194
Office leases	No	196	19	32	32	80	24	9
Ocean-going vessel leases	No	95	95	—	—	—	—	—
Transportation and processing commitments	No	1,079	135	181	146	284	192	141
Min. work commitments ⁵	No	308	203	77	28	—	—	—
Other service contracts	No	131	19	32	9	24	24	23
Stock options and cash units ⁶	Yes – Liability	164	123	41	—	—	—	—
Total		6,582	904	668	1,073	961	1,263	1,713

1 Payments exclude ongoing operating costs related to certain leases, interest on long-term debt, preferred securities charges and payments made to settle derivative contracts.

2 Payments denominated in foreign currencies have been translated at the December 31, 2003 exchange rate.

3 The abandonment obligation represents management's probability weighted, undiscounted best estimate of the cost and timing of future dismantlement, site restoration and abandonment obligations based on engineering estimates and in accordance with existing legislation and industry practice.

4 Subsequent to year end, US\$150 million were redeemed.

5 Minimum work commitments include contracts awarded for capital projects and those commitments related to exploration or drilling obligations.

6 The liability for stock options and cash units recognized on the balance sheet is based on the Company's year end stock price and the number of options and cash units outstanding, adjusted for vesting terms. The amount included in this table includes the full value of unvested options and cash units. Timing of payments is based on vesting. Actual payments are dependent on the Company's stock price at the time of exercise.

January 1, 2004, these contracts are no longer designated hedges of the Eurobond. Subsequent to year end, the Company terminated approximately three-quarters of these contract positions for cash proceeds, before tax, of \$108 million.

The Company has established a system of internal controls to minimize risks associated with its derivatives program and credit risk associated with derivatives counterparties. Management believes its commodity derivatives and fixed priced sales program to be prudent in that it provides a degree of price support during periods of falling commodity prices while providing the ability to participate in price increases and, in the case of certain fixed price sales contracts, guaranteed market access.

Application of Critical Accounting Policies and the Use of Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect reported assets and liabilities, disclosures of contingencies and revenues and expenses. Management is also required to adopt accounting policies that require the use of significant estimates. Actual results could differ from those estimates. A summary of significant accounting policies adopted by Talisman can be found in note 1 to the December 31, 2003, Consolidated Financial Statements. In assisting the Company's Audit Committee to fulfill its financial statement oversight role, management regularly meets and reviews with the Committee the Company's significant accounting policies, estimates and any significant changes thereto including those discussed below.

Management believes the most critical accounting policies, including judgments in their application, that may have an impact on the Company's financial results relate to the accounting for property, plant and equipment, abandonment and goodwill. The rate at which the Company's assets are depreciated or otherwise written off and the abandonment liability provided for are subject to a number of judgments about future events, many of which are beyond management's control. Reserves recognition is central to much of the accounting for an oil and gas company as described below.

Reserves Recognition

Underpinning Talisman's oil and gas assets and goodwill are its oil and gas reserves. Detailed rules and industry practice, to which Talisman adheres, have been developed to provide uniform reserves recognition criteria. However, the process of estimating oil and gas reserves is inherently judgmental. There are two principle sources of uncertainty; technical and commercial. Technical reserves estimates are made using all available geological and reservoir data as well as production performance data. As new data becomes available, including actual reservoir performance, reserves estimates may change. Reserves can be classified as proved or probable with decreasing levels of certainty as to the likelihood that the reserves will be ultimately produced.

Reserves recognition is also impacted by economic considerations. In order for reserves to be recognized they must be reasonably certain of being produced under existing economic and operating conditions, which

is viewed as being at year end commodity prices with a cost profile based on current operations. In particular, in international operations consideration includes the status of field development planning and gas sales contracts. As economic conditions change, primarily as a result of changes in commodity prices and, to a lesser extent, operating and capital costs, marginally profitable production, typically experienced in the later years of a field's life cycle, may be added to reserves or conversely may no longer qualify for reserves recognition.

The Company's reserves and revisions to those reserves, though not separately reported on the Company's balance sheet or income statement, impact the Company's reported net income through the amortization of the Company's property, plant and equipment (PP&E), asset and goodwill impairments and the provision for future abandonment and reclamation costs.

During 2003, Talisman's Board of Directors established a Board committee to review the Company's reserves booking process and related public disclosures and has established the position of an internal qualified reserves evaluator (IQRE). The IQRE provides a report to the Reserves Committee and delivers a regulatory certificate regarding reserves and their related cash flows. The primary responsibilities of the Reserves Committee of the Board of Directors include, amongst other things, reviewing the Company's reserves booking process and recommending to the Board of Directors of Talisman the Company's annual statement of reserves data and other oil and gas information.

Depreciation, Depletion and Amortization Expense (DD&A)

A significant portion of the Company's property, plant and equipment is amortized based on the unit of production method with the remaining assets being amortized equally over their expected useful lives. The unit of production method attempts to amortize the asset's cost over its proved oil and gas reserves base. Accordingly, revisions to reserves or changes to management's view as to the operational life span of an asset will impact the Company's future DD&A expense.

As outlined in the Company's DD&A accounting policy and PP&E note (notes 1(d) and 4 of the Consolidated Financial Statements), \$866 million (2002 – \$1.2 billion) of the Company's Property, Plant and Equipment is not currently subject to DD&A. Half of these costs (\$429 million) relate to development projects such as Angostura and PM-305 that are expected to be on production by 2005, at which time amortization will commence. The remaining half of the \$866 million of non-depleted capital relates to the costs of acquired probable reserves (\$154 million) and incomplete drilling activities, including those wells under evaluation or awaiting production to commence (\$283 million). Uncertainty exists with these costs. For example, if the evaluation of the acquired probable reserves or recently drilled exploration wells were determined to be unsuccessful, the associated capitalized costs would be expensed in the year such determination is made, except that in the case of acquired probable reserves associated with producing fields, these costs would be amortized over the reserve base of the associated producing field. Accordingly, the rate at which these costs are written off depends on management's view of the likelihood of the existence of economically producible reserves.

Asset Impairments

The Company's oil and gas assets and goodwill are subject to impairment tests. An impairment charge is recorded in the year an asset is determined to be impaired. Individual oil and gas assets are considered impaired under the Successful Efforts method if their undiscounted future cash flows fall below their carrying value. Goodwill is considered to be impaired if its fair value, principally determined based on discounted cash flows, falls below its carrying value. Both tests require management to make assumptions regarding cash flows well into the distant future that are subject to revisions due to changes in commodity prices, costs, recoverable reserves, production profiles and in the case of goodwill, discount rates. During the past three years, isolated asset impairments have occurred (2003 – \$30 million; 2002 – \$74 million) however, it is possible that future impairments may be material.

Purchase Price Allocations

The costs of corporate and asset acquisitions are allocated to the acquired assets and liabilities based on their fair value at the time of acquisition. In many cases the determination of fair value requires management to make certain assumptions and estimates regarding future events. Typically in determining fair value, management develops a number of possible future cash flow scenarios to which probabilities are judgmentally assigned. The allocation process is inherently subjective and impacts the amounts assigned to the various individually identifiable assets and liabilities as well as goodwill. The acquired assets and liabilities may span multiple geographical segments and may be amortized at different rates, or not at all as in the case of goodwill or initially for acquired probable reserves. Accordingly, the allocation process impacts the Company's reported assets and liabilities and future net income due to the impact on future depreciation, depletion and amortization expense and impairment tests.

Future Abandonment and Site Restoration Activities

Upon retirement of its oil and gas assets, the Company anticipates incurring substantial costs associated with abandonment and reclamation activities. Estimates of the associated costs are subject to uncertainty associated with the method, timing and extent of future retirement activities. A liability for these costs is accrued on a unit of production basis over the associated reserves base. Accordingly, the annual expense associated with future abandonment and reclamation activities is impacted by changes in the estimates of the expected costs and reserves. During 2003, the abandonment expense included in DD&A was \$132 million. The total abandonment liability is currently estimated at \$2 billion, which is based on management's probability weighted estimate of costs and in accordance with existing legislation and industry practice. If this liability had been estimated to be 10% higher, an additional \$13 million may have been recorded as DD&A during 2003. Past revisions to the abandonment estimate have not been significant.

As indicated in the MD&A section entitled New Accounting Pronouncements, the accounting for Future Abandonment and Site Restoration Activities has changed effective January 1, 2004. A similar change occurred for US GAAP effective January 1, 2003. Under the new accounting requirements, the fair value of the Company's Asset Retirement Obligations (ARO) is to

be recorded as a liability on the Company's balance sheet. In determining the fair value of the Company's ARO liability management develops a number of possible abandonment scenarios to which probabilities are judgmentally assigned. At December 31, 2003, the fair value of the Company's ARO liability is estimated to be \$1.2 billion. As an indication of possible future changes in the estimated liability, if all of the Company's abandonment obligations could be deferred by one additional year, the fair value of the liability would have decreased by approximately \$60 million.

Foreign Exchange Accounting

Talisman's worldwide operations expose the Company to transactions denominated in a number of different currencies which are required to be translated into one currency for financial statement reporting purposes. Talisman's foreign currency translation policy, as detailed in note 1(i) of the Consolidated Financial Statements, is designed to reflect the economic exposure of the Company's operations to the various currencies. The adoption of the US dollar, effective for 2002, as the Company's functional currency is a reflection of Talisman's overall exposure to US dollar denominated transactions, assets and liabilities; oil prices are largely denominated in US dollars as is much of the Company's corporate debt and international capital spending and operating costs. However, the Company's operations in the UK and Canada are largely self-sufficient (self-sustaining) and their economic exposure is more closely tied to their respective domestic currencies. Accordingly, these operations are measured in UK pound sterling and Canadian dollars, respectively. Currently, the Company's foreign exchange exposure principally relates to US dollar denominated UK and Canadian oil sales.

During 2003, the Company's debt was denominated in US dollars, Canadian dollars and UK pound sterling with the UK pound sterling debt effectively swapped into US dollars through the use of cross currency and interest rate swap contracts. During 2003, a portion of the Company's debt (net of cash) was allocated to the self-sustaining Canadian operations based on the Company's net investment in Canada. Foreign exchange gains resulted from the debt allocation as the total amount of net debt allocated exceeded the Company's total Canadian dollar denominated debt.

Production Sharing Contractual Arrangements

A significant portion of the Company's operations outside North America and the North Sea are governed by production sharing contracts (PSCs). Under PSCs, Talisman, along with its working interest partners, typically bears all risk and costs for exploration, development and production. In return, if exploration is successful, Talisman is given the opportunity to recover its investment and operating costs from the production and sale of the associated hydrocarbons ('cost oil'). Talisman is also entitled to receive a share of the 'profit oil', the sharing of which varies from contract to contract. Profit oil is that production in excess of what is required to recover the Company's investment and operating costs. The cost oil, together with the Company's share of profit oil represents Talisman's hydrocarbon entitlement. Talisman records production, sales and reserves based on its working interest ownership. The difference between the Company's working interest ownership and its annual entitlement is accounted for as a royalty expense. In addition, certain of the Company's

contracted arrangements in foreign jurisdictions stipulate that income taxes are to be paid by the respective national oil company out of its entitlement share of production. Such amounts are included in income taxes expense at the statutory tax rate in effect at the time of production.

The amount of cost oil required to recover Talisman's investment and costs in a PSC is dependent on commodity prices while Talisman's share of profit oil is also impacted by commodity prices and the profit oil sharing terms. Accordingly, the amount of royalty paid by Talisman over the term of a PSC and the corresponding net after royalty oil and gas reserves booked by the Company is dependent on the amount of initial investment and past costs yet to be recovered and anticipated future costs, commodity prices and production.

Fair Value of Derivative Financial Instruments under US GAAP

As disclosed in note 1(k) of the Consolidated Financial Statements, during 2003, all of the Company's derivative financial instruments were treated as hedges for Canadian GAAP. Accordingly, gains and losses on these instruments are not recorded in the income statement until the hedged transaction occurs. These instruments are carried at cost. For US GAAP purposes, these instruments are not treated as hedges and are recorded on the balance sheet at fair value with changes in fair value being recorded as either income or an expense. The fair value of certain commodity based instruments are highly volatile. The determination of fair value for certain non-market traded instruments requires management to make significant estimates. In addition, the meaningfulness of an instrument's fair value on December 31, 2003 and the appropriateness of recognizing income based on such daily values should be viewed with caution. In determining the fair value of its commodity based instruments, the Company uses an options pricing model based on market determined price forecasts. For other fair values such as those for its interest rate swaps, forward currency contracts and preferred securities, the Company obtains multiple price quotes from external sources.

Oil and Gas Drilling Rights

Talisman has classified all of its mineral drilling rights as oil and gas properties under the heading property, plant and equipment. We believe this treatment is consistent with industry practice and our understanding of the relevant accounting standards. It is our understanding that the Staff of the Securities and Exchange Commission (SEC) is questioning certain SEC registrants regarding the appropriateness of this accounting treatment, specifically as to whether these costs should be classified as intangible assets on the balance sheet separate from other property, plant and equipment. Further, it is our understanding that this issue is being considered by the US Financial Accounting Standards Board (FASB). We believe resolution of this issue will not materially affect the Company's results of operations.

New Canadian Accounting Pronouncements

The Canadian Institute of Chartered Accountants (CICA) has issued a number of accounting pronouncements, some of which may impact the Company's reported results and financial position in future periods.

Disposal of Long-Lived Assets and Discontinued Operations

Effective for disposition activities initiated after May 1, 2003, this pronouncement expands the scope of what assets or operations are to be reclassified as Discontinued Operations and the conditions required to reclassify them as such. This eliminates a difference between US and Canadian GAAP.

Asset Retirement Obligations (future site restoration and abandonment liabilities)

Effective January 1, 2004, the CICA has adopted a new accounting standard that will change the method of accruing for costs associated with the retirement of fixed assets which an entity is legally obligated to incur. The standard will require entities to record the fair value of a liability for an asset retirement obligation in the period it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Currently, these obligations are provided for using the unit of production method or, for certain assets, using the straight-line method over the estimated remaining lives of the assets. The US has adopted a similar rule commencing January 1, 2003.

The accounting standard requires the retroactive restatement of the Company's financial statements upon adoption in 2004. The adjustment required to the December 31, 2003 balance sheet and income statement to implement this change in accounting would be as follows:

(millions of dollars, except per share amounts)	As Reported December 31, 2003	Adjustment upon adoption of ARO standard in 2004	Restated December 31, 2003
Property, plant and equipment	9,778	407	10,185
Provision for future site restoration	840	311	1,151
Future income taxes	2,088	37	2,125
Retained Earnings	1,844	59	1,903
DD&A expense	1,443	(67)	1,376
Other expenses	16	58	74
Future income tax (recovery)	(51)	3	(48)
Net income	1,007	6	1,013
Net income per share (\$/share)	7.65	0.05	7.70
Diluted net income per share (\$/share)	7.57	0.05	7.62

Impairments of Long-Lived Assets

The CICA issued a new accounting standard on Impairment of Long-Lived Assets. The new standard is effective for 2004. Under this standard, if a long-term asset is identified as being impaired, as determined by its undiscounted future cash flows, the amount of impairment is to be calculated based on the asset's fair value (present value of expected future cash flows). This is consistent with the US GAAP methodology. Prior to this standard, the impairment as calculated under Canadian GAAP was based on the asset's undiscounted future cash flows.

Hedge Accounting

The CICA has issued a new accounting guideline on Hedging Relationships (AcG 13), which is effective for 2004. This guideline, in addition to supplementing and interpreting existing hedging requirements under Canadian GAAP, establishes certain other conditions required before hedge accounting may be applied. Effective January 1, 2004, the Company's US dollar cross currency swap contracts and interest rate swap contracts are no longer designated as hedges of the Eurobond. As a result, on January 1, 2004, in accordance with the Company's accounting policy as detailed in note 1(k) of the December 31, 2003 Consolidated Financial Statements, the Company will record these contracts as an asset on the balance sheet at their fair value of \$123 million, record a deferred gain of \$17 million and an increase to long-term debt of \$106 million, based on the year end exchange rate. The unrealized gain of \$17 million on these contracts at year end will be deferred and amortized over the period to 2009, the original term of the contracts. Starting in January 1, 2004, these contracts will be revalued at the end of each period with changes in their fair value being recorded in other income as a gain or loss. Approximately three-quarters of the swap contracts were terminated in early 2004 for cash proceeds of \$108 million. The termination of these contracts does not accelerate the recognition of the deferred gain into income.

The Company's long-term debts denominated in UK pound sterling and Canadian dollars have been designated as hedges of the Company's net investments in the UK and Canadian self-sustaining operations. Unrealized foreign exchange gains and losses resulting from the translation of these debts are deferred and included in a separate component of shareholders' equity described as cumulative foreign currency translation. Had the Company not designated these debts as hedges of the Company's net investments in its self-sustaining operations, the Company's net income could have been subject to increased volatility in the future upon revaluation into US dollars of the UK pound sterling and Canadian dollar denominated debts.

Variable Interest Entities

In 2003, the CICA issued a new accounting guideline on Consolidation of Variable Interest Entities (AcG 15), which is effective January 1, 2004. AcG 15 provides guidance as to when a company should consolidate another entity into its Consolidated Financial Statements. Simply put, a variable interest entity (VIE) is a corporation, partnership, trust, or any other legal structure used for business purposes that either (i) does not have equity investors with voting rights or (ii) has equity investors that do not provide sufficient financial resources for the entity to support its activities. AcG 15 requires a VIE to be consolidated by a company if that company is subject to a majority of the risk of loss from the VIE's activities, is entitled to receive a majority of the VIE's residual returns, or both. If a company has previously consolidated a VIE but is not subject to a majority of the risk of loss of its activities nor entitled to receive a majority of its residual returns, such a VIE is required to be deconsolidated. Management is currently evaluating the potential impact of this guideline but does not expect its application would have a significant impact on the Company's financial position, operating results or cash flows.

Risks and Uncertainties

Talisman is exposed to a number of risks inherent in exploring for, developing and producing crude oil and natural gas. The process of estimating oil and gas reserves is complex and involves a significant number of decisions and assumptions in evaluating available geological, geophysical, engineering and economic data; therefore, reserves estimates are inherently uncertain. The Company may adjust estimates of proved reserves based on production history, results of exploration and development drilling, prevailing oil and gas prices and other factors, many of which are beyond the Company's control. In addition, there are numerous uncertainties in forecasting the amounts and timing of future production, costs, expenses and the results of exploration and development projects.

The Company's future success depends largely on its ability to find, develop or acquire additional oil and gas reserves that are economically recoverable. Exploration and development drilling may not result in commercially productive reserves. Successful acquisitions require an assessment of a number of factors, many of which are uncertain. These factors include recoverable reserves, exploration potential, future oil and gas prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain.

Oil and gas drilling and producing operations are subject to many risks including the possibility of fire, explosions, mechanical failure, pipe failure, chemical spills, accidental flows of oil, natural gas or well fluids, sour gas releases, and other occurrences or accidents which could result in personal injury or loss of life, damage or destruction of properties, environmental damage, interruption of business, regulatory investigations and penalties and liability to third parties. The Company mitigates insurable risks to protect against significant losses by maintaining a comprehensive insurance program, while maintaining levels and amounts of risk within the Company which management believes to be acceptable. Talisman believes its liability, property and business interruption insurance is appropriate to its business and consistent with common industry practice, although such insurance will not provide coverage in all circumstances.

The Company's operations may be adversely affected by changes in governmental policies and legislation or social instability or other political or economic developments which are not within the control of Talisman including, among other things, a change in crude oil or natural gas pricing policy, the risks of war, terrorism, abduction, expropriation, nationalization, renegotiation or nullification of existing concessions and contracts, taxation policies, economic sanctions, the imposition of specific drilling obligations, the development and abandonment of fields, fluctuating exchange rates and currency controls. In addition, both Indonesia and Algeria are members of the Organization of Petroleum Exporting Countries. Accordingly, Talisman's operations in these countries may be impacted by the application of production quotas. Indonesia, Algeria and Colombia have been subject to recent economic or political instability and social unrest, military or rebel hostilities.

Talisman's financial performance is highly sensitive to prevailing prices of crude oil and natural gas. Fluctuations in crude oil or natural gas prices could have a material adverse effect on the Company's operations and financial condition and the value of its oil and natural gas reserves. Prices for crude oil and natural gas fluctuate in response to changes in the supply of and demand for crude oil and natural gas, market uncertainty and a variety of additional factors that are largely beyond the Company's control. A substantial and extended decline in the prices of crude oil or natural gas could result in delay or cancellation of drilling, development or construction programs, or curtailment in production or result in unutilized long-term transportation commitments all of which could have a material adverse impact on the Company. Talisman conducts an annual assessment of the carrying value of its assets in accordance with Canadian GAAP. If oil and natural gas prices decline, the carrying value of the Company's assets could be subject to downward revisions, which could adversely affect Talisman's reported income for the periods in which the revisions are made. However, Talisman believes that estimates of forward-looking prices it uses in its planning process are realistic.

Talisman's Consolidated Financial Statements are presented in Canadian dollars. Results of operations are affected primarily by the exchange rates between the Canadian dollar, the US dollar and the UK pound sterling. These exchange rates have varied substantially in the last five years. Most of the Company's revenue is received in or is referenced to US dollar denominated prices, while the majority of Talisman's expenditures are denominated in Canadian dollars, US dollars and UK pound sterling. A change in the relative value of the Canadian dollar against the US dollar would also result in an increase or decrease in our US dollar denominated debt, as expressed in Canadian dollars and the related interest expense.

All phases of the oil and natural gas business are subject to environmental regulation pursuant to a variety of laws and regulations in Canada, the UK, the US and other countries in which Talisman does business. These regulatory regimes are laws of general application that apply to the Company's business in the same manner as they apply to other companies or enterprises in the energy industry. Environmental legislation imposes, among other things, restrictions, liabilities and obligations in connection with the generation, handling, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment. Environmental legislation also requires that pipelines, wells, facility sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations, including exploration and development projects, may require the submission and approval of environmental impact assessments or permit applications. Compliance with environmental legislation can require significant expenditures and failure to comply with environmental legislation may result in the imposition of fines and penalties and liability for clean up costs and damages. Additionally, the Company's business is

subject to the trend toward increased civil liability for environmental matters. Although Talisman currently believes that the costs of complying with environmental legislation and dealing with environmental civil liabilities will not have a material adverse effect on the Company's financial condition or results of operations, there can be no assurance that such costs in the future will not have such an effect. Talisman expects to incur site restoration costs over a prolonged period as existing fields are depleted. The Company provides for future abandonment and reclamation costs in its Consolidated Financial Statements in accordance with Canadian GAAP. Additional information regarding future abandonment and reclamation costs is set forth in the notes to the annual Consolidated Financial Statements.

In 1994, the United Nations' Framework Convention on Climate Change came into force and three years later led to the Kyoto Protocol (the "Protocol") which requires, upon ratification, certain nations to reduce their emissions of carbon dioxide and other greenhouse gases. In December 2002, the Canadian federal government ratified the Protocol. If certain conditions are met and the Protocol enters into force internationally, Canada will be required to reduce its greenhouse gas (GHG) emissions to 6% below 1990 levels over the period beginning in 2008 and ending in 2012. Currently, Canadian oil and gas producers are in discussions with the provincial and federal levels of government regarding implementation mechanisms for the industry. It is premature to predict what impact implementation could have on Canadian oil and gas producers but it is likely that any mandated reduction in GHG emissions will result in increased costs. The federal government has stated that these costs would not be expected to exceed \$15/tonne of carbon dioxide emissions reduced and that producers would not be required to reduce GHG emissions per unit of production by more than 15%. The federal government has also indicated its support for several important principles that are intended to protect the competitiveness of the oil and gas industry beyond 2012, including a 10-year emissions target lock-in period for all new projects and additional flexibility mechanisms for achieving compliance.

The UK has also ratified the Kyoto Protocol, with a reduction commitment of 12.5% below 1990 levels by 2008 – 2012. The UK Government, however, has set a more aggressive national goal of moving towards a 20% reduction in carbon dioxide emissions by 2010. Talisman's UK installations will participate in the first phase of the European Union Emission Trading Scheme ("EU ETS"), which runs from 2005 to 2007, inclusive. The UK Government's draft National Allocation Plan ("NAP") for the first phase of the EU ETS was published for broad consultation in January 2004. When finalized in September 2004, the NAP will dictate the total cap on carbon dioxide emissions for the covered sectors, the methods for allocating emission allowances to covered installations and the number of emission allowances to be allocated to each covered installation. Cost of compliance will vary with a number of factors including the final allocation numbers and liquidity of the carbon markets.

From time to time, Talisman is the subject of litigation arising out of the Company's operations. Damages claimed under such litigation, including the litigation discussed below, may be material or may be indeterminate and the outcome of such litigation may materially impact the Company's financial condition or results of operations. While Talisman assesses the merits of each lawsuit and defends itself accordingly, the Company may be required to incur significant expenses or devote significant resources to defending itself against such litigation. These claims are not currently expected to have a material impact on the Company's financial position.

Talisman continues to be subject to a lawsuit brought by the Presbyterian Church of Sudan and others under the Alien Tort Claims Act in the United

States District Court for the Southern District of New York. The lawsuit, which is seeking class action status, alleges that the Company conspired with, or aided and abetted, the Government of Sudan to commit violations of international law in connection with the Company's now disposed of indirect interest in oil operations in Sudan. In July 2003, Talisman filed a motion to dismiss the lawsuit for lack of personal jurisdiction of the Court over Talisman. In August 2003, the plaintiffs filed a motion seeking certification of the case as a class action. Talisman is in the process of challenging this certification. No decision is expected on either of these motions prior to the third quarter of 2004. Talisman believes these claims to be entirely without merit and is continuing to vigorously defend itself against this lawsuit and does not expect this to have a material adverse effect.

Outlook for 2004

				Estimated for 2004	Actual 2003
Cash flow¹				\$2.2-2.8 billion	\$2.7 billion
Cash flow per share¹				\$17-22	\$21.21
Exploration and development spending (millions of dollars)		Exploration	Development	Total	Total E&D
North America		431	704	1,135	1,109
North Sea		119	487	606	496
Southeast Asia		62	253	315	316
Algeria		—	44	44	34
Trinidad		40	130	170	130
Other		85	—	85	95
		737	1,618	2,355	2,180
Production (daily average)			Lower estimate	Upper estimate	Actual 2003
Oil and liquids (bbls/d)					
North America			54,000	56,000	59,578
North Sea			109,000	122,000	113,075
Southeast Asia			33,000	38,000	24,430
Algeria			14,000	16,000	6,594
Sudan			—	—	13,039
			210,000	232,000	216,716
Natural gas (mmcf/d)					
North America			885	905	864
North Sea			120	130	109
Southeast Asia			225	240	117
			1,230	1,275	1,090
Barrel of oil equivalent (mboe/d)			415	445	398
Commodity price and exchange rate assumptions					
US\$/bbl WTI oil price			25	30	30.99
US\$/mmbtu NYMEX			4.75	5.50	5.44
C\$/US\$ exchange rate			0.77	0.73	0.71
C\$/£ exchange rate			2.50	2.25	2.29

¹ Cash flow and cash flow per share are considered to be non-GAAP financial measures. The estimate for 2004 is calculated using the same method as in 2003. A 2004 estimate of net income and net income per share has not been provided due to the inherent difficulties of estimating certain non-cash expenses, such as dry hole, property impairments and non-cash stock based compensation.

Talisman expects to increase production 4-12% in 2004. Production for 2004 is expected to average approximately 415,000-445,000 boe/d with a full year's production from the PM-3 CAA development and Algeria and increased North America natural gas production resulting from increased exploration and development spending and the impact of the recently completed infrastructure projects.

The Company expects cash flow per share of \$17-22 in 2004 (\$2.2-2.8 billion), assuming US\$25-30/bbl WTI oil, US\$4.75-5.50/mmbtu NYMEX gas and C\$1=US\$0.73-0.77. Unit operating costs are expected to increase by 5-10% largely due to an anticipated strengthening of the UK pound sterling against the Canadian dollar. However, unit production costs, in addition to being impacted by currency exchange rates are dependent on achieving expected production levels. Net capital spending is expected to be \$2.35 billion and excludes significant corporate and asset acquisitions. The Company anticipates participating in the drilling of 640 North American and 118 international wells during 2004. Cash flow is expected to be sufficient to fund budgeted capital spending during 2004.

North America

Natural gas continues to be the focus of the Company's exploration activities in North America with a shift towards the remaining underdeveloped parts of the Western Canadian Sedimentary Basin supplemented by low risk oil projects. North American natural gas production in 2004 is expected to increase between 2-5% to average between 885-905 mmcf/d, while oil and liquids is expected to average 54,000-56,000 bbls/d, with the Company spending less than 30% of the North America budget on oil exploration and development. The Company expects to spend \$1.1 billion on capital projects and drilling in 2004, up 2% from 2003. The Company plans to participate in approximately 640 wells in 2004, including 11 in Appalachia. Unit operating costs are expected to increase to slightly over \$5/boe due to industry wide cost issues such as higher power and water handling charges.

North Sea

North Sea production is expected to average 109,000-122,000 bbls/d and 120-130 mmcf/d in 2004. The Company's North Sea strategy is to focus on development projects and adjacent exploration opportunities around core operated properties and infrastructure. Of the \$606 million of planned capital spending, a 22% increase over 2003, 80% is related to development projects. Eight exploration and 25 development wells are planned for 2004. Total North Sea operating expenses are expected to increase in 2004 with the addition of Gyda and a strengthening of the pound sterling against the Canadian dollar. At current exchange rates (approximately £1=C\$2.50) unit operating costs could be in the \$14/boe range.

Southeast Asia

Natural gas sales in Indonesia have recently increased with new sales to Singapore and increased demand from Caltex. Indonesian natural gas sales are expected to average 135-140 mmcf/d in 2004. Discussions are currently underway to secure additional long-term gas sales in Southeast Asia to monetize Corridor's large existing natural gas reserves. An expansion of the gas plant facilities at Corridor PSC from 300-700 mmcf/d over the next three years is planned in order to accommodate additional anticipated gas sales. This plant expansion accounts for a majority of the planned capital spending of \$65 million in Indonesia during 2004. Oil and liquids production in the Indonesian blocks is expected to average 12,000-13,000 bbls/d with natural decline.

With the startup of the PM-3 CAA development project, Talisman's oil and liquids production in Malaysia/Vietnam is expected to average between 21,000-25,000 bbls/d. Natural gas production from the project is expected to average 90-100 mmcf/d during 2004. Total Malaysia/Vietnam daily average production in 2004 is expected to exceed 36,000 boe/d, with an upper range of 42,000 boe/d.

Talisman's capital requirements in Malaysia/Vietnam are expected to fall in 2004 due to the commissioning of the PM-3 CAA development project in 2003. Total forecasted capital spending in Malaysia/Vietnam is expected to be \$250 million and will be primarily focused on drilling 32 development wells in PM-3 CAA. Five exploration wells are also planned for 2004: three on PM-3 CAA and Block PM-305 and two on Block 46-02 offshore Vietnam. Development of the South Angsi discovery in Block PM-305, with first oil expected in 2005, will begin in 2004 with the drilling of two development wells and facilities fabrication.

Operating costs in Southeast Asia are expected to decrease to approximately \$3/boe in 2004 with the higher anticipated volumes from PM-3 CAA and additional anticipated natural gas sales in Indonesia.

Algeria

Production from the Ourhoud and MLN fields in Algeria is expected to average 14,000-16,000 bbls/d. Operating costs are expected to fall to below \$6/boe due to higher forecasted production. A capital budget of \$44 million is estimated and includes drilling six wells in the Greater MLN area, 10 wells at Ourhoud and an expansion of the Greater MLN facility to increase production capacity.

Trinidad

Capital spending in Trinidad is budgeted at \$170 million with the majority related to the completion of the Angostura oil and gas development project on offshore Block 2(c), including facilities construction and participation in drilling 15 development wells. First production is expected in early 2005. Talisman expects to participate in drilling four offshore exploration and appraisal wells, two each on Blocks 2(c) and 3(a). The Company expects to complete an onshore seismic program in the Eastern Block prior to drilling in 2005.

Other

The Company is actively exploring in Colombia where it expects to spend \$28 million in 2004 to participate in one exploration well and acquire seismic. The Company drilled its first prospect in Alaska in early 2004 with a \$15 million budget. The Company also plans to conduct a seismic program in Block 10 in Qatar and to continue technical evaluation of its acreage offshore East Coast Canada.

Economic Assumptions

Talisman's 2004 business plan was formulated on the assumption of US\$25-30/bbl WTI oil and US\$4.75-5.50/mmbtu NYMEX gas prices. The 2004 business plan also incorporates exchange rate assumptions of C\$1=US\$0.73-0.77 and £1=C\$2.25-2.50.

Currently, Talisman has committed approximately 12% of its anticipated 2004 North American natural gas production under both commodity sales contracts and commodity price derivative contracts at an average price of \$5/mcf. In addition, approximately 37% of the Company's 2004 anticipated oil and liquids production has been hedged with 56,000 bbls/d using collars with floor and ceiling prices averaging US\$24-29/bbl and 23,000 bbls/d fixed at an average price of US\$28/bbl.

A summary of the contracts outstanding at year end can be found in notes 9 and 10 of the Consolidated Financial Statements. Additional discussion of the Company's commodity price hedging program can be found in the MD&A section entitled 'Derivative Financial Instruments and Commodity Sales Contracts'.

Liquidity

An increase in the Company's 2004 year end net debt position is anticipated due to an expected softening of commodity prices, the debt refinancing of the redeemed US\$150 million of preferred securities and an increase in planned capital spending. Significant acquisitions or dispositions, a change from expected commodity prices or the continuation of share repurchases would impact the Company's projected 2004 year end net debt position.

Sensitivities

Talisman's financial performance is affected by factors such as changes in production volumes, commodity prices and exchange rates. The estimated impact of these factors on the Company's 2004 financial performance is summarized in the following table and is based on a WTI oil price of US\$30/bbl, a NYMEX natural gas price of US\$5/mmbtu and exchange rates of C\$1=US\$0.76 and £1=C\$2.50.

Approximate impact in 2004

(millions of dollars)	Net Income	Cash Flow ¹
Volume changes		
Oil – 1,000 bbls/d	4	7
Natural gas – 10 mmcf/d	6	13
Price changes ²		
Oil – US\$1.00/bbl	35	36
Natural gas (North America) ³ – C\$0.10/mcf	15	21
Exchange rate changes		
US\$ increased by US\$0.01	24	38
£ increase by C\$0.031	(8)	1

1 Cash flow is a non-GAAP measure, the components of which are set out in note 14 of the Consolidated Financial Statements.

2 The impact of commodity contracts outstanding for 2004 has been included.

3 Price sensitivity on natural gas relates to North American natural gas only. The Company's exposure to changes in North Sea and Malaysia/Vietnam natural gas prices is not material. Most of the Indonesia natural gas price is based on the price of crude oil and accordingly has been included in the price sensitivity for oil except for a small portion which is sold at a fixed price.

Summary of Quarterly Results

The following is a summary of quarterly results of the Company for the eight most recently completed quarters:

(millions of Canadian dollars, unless otherwise stated)		Three months ended				
		Total Year	Dec. 31	Sept. 30	June 30	March 31
2003	Total revenue	4,477	1,097	1,047	993	1,340
	Net income ¹	1,007	107	126	201	573
	Net income available to common shareholders	985	102	120	196	567
	Cash flow	2,729	644	640	600	845
	Total assets	11,365	11,365	11,219	11,066	11,434
	Total long-term liabilities	5,188	5,188	5,240	5,119	5,617
	Capital expenditures					
	Exploration	784	221	215	165	183
	Development	1,396	437	360	327	272
	Per common share (dollars)					
	Net income ¹	7.65	0.80	0.94	1.52	4.37
	Diluted net income	7.57	0.78	0.92	1.50	4.32
	Cash flow	21.21	5.03	4.99	4.65	6.52
	Daily average production					
	Oil and liquids (bbls/d)	216,716	229,166	202,008	188,682	247,369
	Natural gas (mmcf/d)	1,090	1,138	1,064	1,061	1,096
	Total (mboe/d)	398	419	379	365	430
2002	Total revenue	4,452	1,242	1,110	1,111	989
	Net income ¹	524	182	151	90	101
	Net income available to common shareholders	500	176	145	84	95
	Cash flow	2,645	759	657	652	577
	Total assets	11,594	11,594	11,471	10,996	11,032
	Total long-term liabilities	6,103	6,103	5,763	5,655	5,658
	Capital expenditures					
	Exploration	628	174	146	130	178
	Development	1,220	283	297	256	384
	Per common share (dollars)					
	Net income ¹	3.73	1.33	1.08	0.62	0.71
	Diluted net income	3.67	1.31	1.06	0.61	0.70
	Cash flow	19.73	5.72	4.87	4.84	4.31
	Daily average production					
	Oil and liquids (bbls/d)	272,740	270,582	267,393	275,157	277,971
	Natural gas (mmcf/d)	1,036	1,028	1,024	1,051	1,044
	Total (mboe/d)	445	442	438	450	452

1 Net income and net income before discontinued operations and extraordinary items are the same.

The following discussion highlights some of the more significant factors that impacted the net income in the eight most recently completed quarters.

In the first quarter of 2003, the gain on the sale of the Sudan operations increased net income by \$296 million. The sale of these operations contributed to the drop in revenues during the following three quarters of 2003, which was partially offset by production increases in other areas and continued high commodity prices. Net income during the second quarter of 2003 was increased \$160 million due to a reduction in the Canadian federal and provincial tax rates. The Company began recording stock-based

compensation in the second quarter of 2003. The second quarter's net income was reduced by a \$105 million (\$70 million after tax) catch-up expense relating to outstanding stock options. The third and fourth quarters of 2003 included an additional \$80 million (\$50 million after tax) of stock-based compensation expense.

During the second quarter of 2002 the Company recorded a \$128 million future tax expense related to an increase in UK corporate tax rates. Total revenue generally increased throughout the four quarters of 2002. A decrease in production primarily due to scheduled maintenance and other operational issues during the third and fourth quarters of 2002 was more than offset by higher commodity prices.



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Drilling in the Foothills

The Board of Directors is responsible for the Consolidated Financial Statements but has delegated responsibility for their preparation to management.

Management has prepared the Consolidated Financial Statements in accordance with accounting principles generally accepted in Canada (with a reconciliation to accounting principles generally accepted in the United States). If alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has ensured that the Consolidated Financial Statements are presented fairly in all material respects. Management has also prepared the financial information presented elsewhere in the annual report and ensured that it is consistent with information in the Consolidated Financial Statements.

Talisman maintains internal accounting and administrative controls designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that assets are appropriately accounted for and adequately safeguarded.

The Board of Directors is responsible for reviewing and approving the Consolidated Financial Statements and Management's Discussion and Analysis and, primarily through its Audit Committee, ensures that management fulfills its responsibilities for financial reporting.

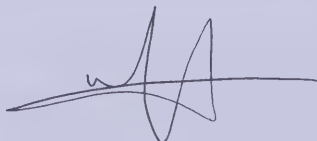
The Audit Committee is appointed by the Board and is composed entirely of unrelated, independent Directors. The Audit Committee meets regularly with management, and with the internal and external auditors, to discuss internal controls and reporting issues and to satisfy itself that each party is properly discharging its responsibilities. It reviews the Consolidated Financial Statements and the external auditors' report. The Audit Committee also considers, for review by the Board and approval by the shareholders, the engagement or reappointment of the external auditors.

Ernst & Young LLP, the external auditors, have audited the Consolidated Financial Statements in accordance with auditing standards generally accepted in Canada and the United States on behalf of the shareholders. Ernst & Young LLP have full and free access to the Audit Committee.



James W. Buckee
President and Chief Executive Officer

February 27, 2004



Michael D. McDonald
Executive Vice-President, Finance and Chief Financial Officer

Auditors' Report

To the Shareholders of Talisman Energy Inc.

We have audited the Consolidated Balance Sheets of Talisman Energy Inc. as at December 31, 2003 and 2002 and the Consolidated Statements of Income, Retained Earnings and Cash Flows for each of the years in the three year period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian and US generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these Consolidated Financial Statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and 2002 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2003 in accordance with Canadian generally accepted accounting principles. We also report that, in our opinion, these principles have been applied, except for the change in the method of accounting for goodwill as explained in note 1(o) to the Consolidated Financial Statements, on a basis consistent with that of the preceding year.

Calgary, Canada
February 27, 2004



Ernst & Young LLP
Chartered Accountants

Consolidated Balance Sheets

(December 31)

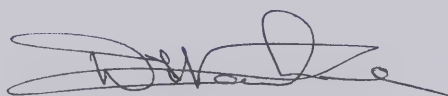
(millions of Canadian dollars)	2003	2002
Assets		
Current		
Cash and cash equivalents	98	27
Accounts receivable	760	719
Inventories (note 3)	100	147
Prepaid expenses	17	24
	975	917
Accrued employee pension benefit asset (note 16)	63	67
Other assets	76	99
Goodwill (note 2)	473	469
Property, plant and equipment (note 4)	9,778	10,042
	10,390	10,677
Total assets	11,365	11,594
Liabilities		
Current		
Accounts payable and accrued liabilities	1,064	803
Income and other taxes payable	154	186
	1,218	989
Deferred credits	57	57
Provision for future site restoration (note 10)	840	813
Long-term debt (note 5)	2,203	2,997
Future income taxes (note 13)	2,088	2,236
	5,188	6,103
Contingencies and commitments (note 10)		
Shareholders' equity		
Preferred securities (note 6)	431	431
Common shares (note 7)	2,725	2,785
Contributed surplus	73	75
Cumulative foreign currency translation (note 8)	(114)	140
Retained earnings	1,844	1,071
	4,959	4,502
Total liabilities and shareholders' equity	11,365	11,594

See accompanying notes.

On behalf of the board:



Douglas D. Baldwin
Chairman of the Board



Dale G. Parker
Director

Consolidated Statements of Income

(Years ended December 31)

(millions of Canadian dollars)	2003	2002	2001
Revenue			
Gross sales	5,295	5,299	5,047
Less royalties	894	927	989
Net sales	4,401	4,372	4,058
Other (note 11)	76	80	82
Total revenue	4,477	4,452	4,140
Expenses			
Operating	1,099	1,115	946
General and administrative	152	138	108
Depreciation, depletion and amortization	1,443	1,495	1,313
Dry hole	251	174	113
Exploration	213	185	147
Interest on long-term debt	137	164	139
Stock-based compensation (note 7)	185	—	—
Other (note 12)	16	113	78
Total expenses	3,496	3,384	2,844
Gain on sale of Sudan operations (note 17)	296	—	—
Income before taxes	1,277	1,068	1,296
Taxes (note 13)			
Current income tax	229	258	342
Future income tax (recovery)	(51)	162	72
Petroleum revenue tax	92	124	149
	270	544	563
Net income	1,007	524	733
Preferred security charges, net of tax	22	24	24
Net income available to common shareholders	985	500	709
Per common share (Canadian dollars) (note 15)			
Net income	7.65	3.73	5.25
Diluted net income	7.57	3.67	5.16
Average number of common shares outstanding (millions)	129	134	135
Diluted number of common shares outstanding (millions)	130	136	137

See accompanying notes.

Consolidated Statements of Retained Earnings

(Years ended December 31)

(millions of Canadian dollars)	2003	2002	2001
Retained earnings, beginning of year	1,071	787	257
Net income	1,007	524	733
Common share dividend	(90)	(80)	(81)
Purchase of common shares	(122)	(136)	(98)
Preferred security charges, net of tax	(22)	(24)	(24)
Retained earnings, end of year	1,844	1,071	787

See accompanying notes.

Consolidated Statements of Cash Flows

(Years ended December 31)

(millions of Canadian dollars)	2003	2002	2001
Operating			
Net income	1,007	524	733
Items not involving current cash flow (note 14)	1,509	1,936	1,614
Exploration	213	185	147
Cash flow	2,729	2,645	2,494
Deferred gain on unwound hedges	(9)	(43)	52
Changes in non-cash working capital (note 14)	(104)	(163)	(177)
Cash provided by operating activities	2,616	2,439	2,369
Investing			
Corporate acquisitions (note 2)	—	—	(1,213)
Proceeds on sale of Sudan operations (note 17)	1,012	—	—
Capital expenditures			
Exploration, development and corporate	(2,218)	(1,874)	(1,912)
Acquisitions (note 2)	(661)	(244)	(186)
Proceeds of resource property dispositions	63	30	47
Investments	(11)	(36)	—
Changes in non-cash working capital	82	2	52
Cash used in investing activities	(1,733)	(2,122)	(3,212)
Financing			
Long-term debt repaid	(791)	(1,397)	(568)
Long-term debt issued	292	1,417	1,617
Common shares purchased (net of proceeds on shares issued)	(184)	(184)	(117)
Common share dividends	(90)	(80)	(81)
Preferred security charges	(38)	(42)	(42)
Deferred credits and other	27	(21)	(25)
Cash (used in) provided by financing activities	(784)	(307)	784
Effect of translation on foreign currency cash	(28)	—	—
Net increase (decrease) in cash	71	10	(59)
Cash and cash equivalents, beginning of year	27	17	76
Cash and cash equivalents, end of year	98	27	17

See accompanying notes.

Notes to the Consolidated Financial Statements

(tabular amounts in millions of Canadian dollars (" \$" or "C\$") except as noted)

1. Significant Accounting Policies

The Consolidated Financial Statements of Talisman Energy Inc. ("Talisman" or the "Company") have been prepared by management in accordance with Canadian generally accepted accounting principles. A summary of the differences between accounting principles generally accepted in Canada and those generally accepted in the United States ("US") is contained in note 19 to these statements.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates.

a) Consolidation

The Consolidated Financial Statements include the accounts of Talisman and its subsidiaries. A substantial portion of Talisman's activities is conducted jointly with others and the Consolidated Financial Statements reflect only the Company's proportionate interest in such activities.

b) Inventories

Product inventories are valued at the lower of average cost and market value. Materials and supplies are valued at the lower of average cost and net realizable value.

c) Property, plant and equipment

The successful efforts method is used to account for oil and gas exploration and development costs. Under this method, acquisition costs of oil and gas properties and costs of drilling and equipping development wells are capitalized. Costs of drilling exploratory wells are initially capitalized and, if subsequently determined to be unsuccessful, are charged to dry hole expense. All other exploration costs, including geological and geophysical costs and annual lease rentals, are charged to exploration expense when incurred. Producing properties and significant unproved properties are assessed annually, or more frequent as economic events dictate, for potential impairment. Any impairment loss is the difference between the carrying value of the asset and its net recoverable amount (undiscounted).

d) Depreciation, depletion and amortization

Capitalized costs of proved oil and gas properties are depleted using the unit of production method. For purposes of these calculations, production and reserves of natural gas are converted to barrels on an energy equivalent basis.

Successful exploratory wells and development costs are depleted over proved developed reserves while acquired resource properties with proved reserves, including offshore platform costs, are depleted over proved reserves. Acquisition costs of probable reserves are not depleted or amortized while under active evaluation for commercial reserves. Costs are transferred to depletable costs as proved reserves are recognized. At the date of acquisition, an evaluation period is determined after which any remaining probable reserve costs associated with producing fields are transferred to depletable costs; costs not associated with producing fields are amortized over a period not exceeding the remaining lease term.

Costs associated with significant development projects are not depleted until commercial production commences. Unproved land acquisition costs that are individually immaterial are amortized on a straight-line basis over the average lease term until properties are determined to be productive or impaired. Gas plants, net of estimated salvage values, are depreciated on a straight-line basis over their estimated remaining useful lives, not to exceed the estimated remaining productive lives of related fields. Pipelines and corporate assets are depreciated using the straight-line method at annual rates of 7% and 4% to 33%, respectively.

e) Future site restoration

Estimated costs of future dismantlement, site restoration and abandonment of oil and gas properties, including offshore production platforms, are provided for using the unit of production method while those of gas plants and facilities are provided for using the straight-line method at rates approximating their useful lives but not exceeding the estimated remaining productive lives of related fields. The annual provision is included within depletion, depreciation and amortization expense and is based on engineering estimates and in accordance with existing legislation and industry practice. Expenditures are charged against the accumulated provision as incurred. When a property is disposed of, the associated accumulated provision is eliminated and included in determination of the gain or loss on disposal.

f) Capitalized interest

Interest costs associated with major development projects are capitalized until the necessary facilities are completed and ready for use.

g) Royalties

Certain of the Company's foreign operations are conducted jointly with the respective national oil companies. These operations are reflected in the Consolidated Financial Statements based on Talisman's working interest in such activities. All other government stakes, other than income taxes, are considered to be royalty interests. Royalties on production from these joint foreign operations represent the entitlement of the respective governments to a portion of Talisman's share of crude oil, liquids and natural gas production and are recorded using rates in effect under the terms of contracts at the time of production.

h) Petroleum Revenue Tax

United Kingdom Petroleum Revenue Tax ("PRT") is accounted for using the life of the field method whereby total future PRT is estimated using current reserves and anticipated costs and prices and charged to income based on net operating income as a proportion of estimated future net operating income. Changes in the estimated total future PRT are accounted for prospectively.

i) Foreign currency translation

Effective January 1, 2002, the Company adopted the US dollar as its functional currency. Prior to January 1, 2002, the functional currency of the Company was the Canadian dollar. The Company's financial results have been reported in Canadian dollars as explained below.

The Company's self-sustaining operations, which include the Canadian and UK operations, are translated into US dollars using the current rate method, whereby assets and liabilities are translated at period-end exchange rates while revenues and expenses are converted using average rates for the period. Gains and losses on translation to US dollars relating to self-sustaining operations are deferred and included in a separate component of shareholders' equity described as cumulative foreign currency translation.

The remaining foreign operations are not considered self-sustaining and are translated using the temporal method. Under this method, monetary assets and liabilities denominated in foreign currencies are translated at exchange rates in effect at the balance sheet date. Non-monetary assets and liabilities denominated in foreign currencies are translated at rates in effect on the dates the assets were acquired or liabilities were assumed. Revenues and expenses are translated at rates of exchange prevailing on the transaction dates. Gains and losses on translation are reflected in income when incurred.

The Company's financial results have been reported in Canadian dollars with amounts translated to Canadian dollars as follows: assets and liabilities at the rate of exchange in effect at the applicable balance sheet date and revenues and expenses at the average exchange rates for the periods. The Company's share capital accounts including its preferred securities, common shares and contributed surplus are translated at rates in effect at the time of issuance. Unrealized gains and losses resulting from the translation to Canadian dollars are included in the cumulative foreign currency translation account.

j) Employee benefit plans

The cost of pensions and other retirement benefits earned by employees is determined using the projected benefit method prorated on service and management's best estimate of expected plan investment performance, salary escalation and retirement ages of employees. There is uncertainty relating to the assumptions used to calculate the net benefit plan expense and accrued benefit obligation which are long term, consistent with the nature of employee future benefits.

The discount rate used to determine the accrued benefit obligation is determined by reference to market interest rates at the measurement date on high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments. For purposes of calculating the expected return on plan assets, those assets are valued at fair value. The excess of the net actuarial gain or loss over 10% of the greater of the accrued benefit obligation and the fair value of plan assets at the beginning of the year is amortized over the average remaining service life of active employees. The transitional asset and obligations are being amortized over the average remaining service period of active employees expected to receive benefits under the benefit plans.

k) Derivative financial instruments and commodity contracts

The Company may enter into derivative financial instruments to hedge against adverse fluctuations in foreign exchange rates, electricity rates, interest rates and commodity prices. Payments or receipts on derivative financial instruments that are designated and effective as hedges are recognized in income concurrently with the hedged transaction and are recorded in the consolidated statements of income and cash flows in the line item associated with the hedged transaction. For example, gains and losses on commodity hedges are included in revenues.

If the derivative financial instrument that has been designated as a hedge is terminated or is no longer designated as part of the hedging relationship, the gain or loss at that date is deferred and recognized concurrently with the anticipated transaction. If it is no longer probable that the anticipated transaction will occur substantially as and when identified at the inception of the hedging relationship, the gain or loss at that date is recognized immediately. Subsequent changes in the value of the derivative financial instrument are reflected in income. Any derivative financial instrument that does not constitute a hedge is recorded at fair value with any resulting gain or loss reflected in income.

All of the Company's derivative financial instruments outstanding during 2003 met the hedging requirements under Canadian GAAP. The hedging requirements as amended by AcG 13, consist of the designation of the instrument as a hedge, the identification of the nature of the risk exposure being hedged and that there is reasonable assurance that the instrument is expected to be an effective hedge throughout its term. In addition, in the case of anticipated transactions, it is also probable that the transaction designated as being hedged will occur. The Company assesses, both at the hedge's inception and on an ongoing basis, whether the derivative financial instruments that have been designated as hedges are highly effective in offsetting changes in fair value or cash flows of the hedged items.

The Company enters into commodity contracts in the normal course of business including contracts with fixed or optional pricing terms. The contracts outstanding at December 31, 2003 are disclosed in note 9. The Company's production is expected to be sufficient to deliver all required volumes under these contracts. No amounts are recognized in the Consolidated Financial Statements related to these contracts until such time as the associated volumes are delivered.

l) Income taxes

Talisman uses the liability method to account for income taxes. Under the liability method, future income taxes are based on the differences between assets and liabilities reported for financial accounting purposes from those reported for income tax. Future income tax assets and liabilities are measured using substantively enacted tax rates. The impact of a change in tax rate is recognized in net income in the period in which the tax rate is substantively enacted.

Certain of the Company's contractual arrangements in foreign jurisdictions stipulate that income taxes are to be paid by the respective national oil company out of its entitlement share of production. Such amounts are included in income tax expense at the statutory tax rate in effect at the time of production.

m) Revenue recognition

Revenues associated with the sale of crude oil, natural gas and liquids represents the sales value of the Company's share of petroleum production during the year (the entitlement method). Differences between production and amounts sold are not significant. Amounts received under take-or-pay gas sales contracts in respect of undelivered volumes are accounted for as deferred income.

n) Stock-based compensation

Talisman has stock option and cash unit plans for employees and directors, which are described in note 7. In 2003, the option plans were amended to provide holders of stock options the choice upon exercise to receive a cash payment in exchange for surrendering the option. Commencing in 2003, as a result of the amendment to the stock option plans, the Company began recording stock-based compensation expense based on the appreciated value of the outstanding stock options and cash units as determined using the period end closing share price.

A liability for the stock-based compensation is included in accounts payable and accrued liabilities.

o) Goodwill

Goodwill represents the excess purchase price over the fair value of identifiable assets and liabilities acquired in business combinations. Effective January 1, 2002, goodwill ceased to be amortized. Goodwill amortization of \$10 million was expensed in 2001. Goodwill is subject to ongoing annual impairment reviews, or more frequent as economic events dictate, based on the fair value of reporting units. The fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's individual assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount. The Company's reporting units are consistent with the geographic segments included in note 18.

p) Net income and diluted net income per share

Net income per share is calculated by dividing net income after deducting preferred security charges, net of tax, by the weighted average number of common shares outstanding. Diluted net income per share is calculated giving effect to the potential dilution that could occur if convertible instruments, such as stock options, were exercised in exchange for common shares.

The Company uses the treasury method to determine the dilutive impact of convertible instruments. This method assumes that any proceeds from the exercise of a convertible instrument would be used to purchase common shares at the average market price during the period.

q) Cash and cash equivalents

Cash and cash equivalents include short-term investments with an original maturity of three months or less.

2. Acquisitions

The following acquisitions have been accounted for using the purchase method and the results have been included in these Consolidated Financial Statements from the date of acquisition.

Significant Corporate Acquisitions

Petromet Resources Limited

In May 2001, Talisman acquired Petromet Resources Limited ("Petromet"), an oil and gas exploration and development company, for \$765 million and long-term debt assumed of \$57 million.

Net Assets Acquired	
Property, plant and equipment	795
Goodwill	301
Net non-cash working capital	(6)
Future income tax	(264)
	826
Less acquisition costs	(4)
	822

Lundin Oil AB

In August 2001, Talisman acquired Lundin Oil AB ("Lundin"), an oil and gas exploration and development company, for \$431 million (net of cash on hand) and long-term debt assumed of \$70 million.

Net Assets Acquired	
Property, plant and equipment	515
Goodwill	176
Net non-cash working capital	(19)
Future income tax	(158)
	514
Less acquisition costs	(13)
	501

Other Acquisitions

During 2003, Talisman completed a number of individually insignificant oil and gas property and corporate acquisitions for a total cost of \$768 million, comprised of \$661 million in cash, \$70 million of assumed debt and working capital deficiency and \$37 million of properties exchanged. Four of the transactions account for the majority of the acquisitions and were acquired for a total cost of \$626 million. These four acquisitions included oil and gas properties in North America and the North Sea and a company with midstream assets in North America.

Net assets acquired	North America	North Sea	Combined
Property, plant and equipment	541	112	653
Goodwill	—	31	31
Future income tax	(27)	(31)	(58)
	514	112	626

Goodwill Continuity

	2003	2002	2001
Opening balance at January 1	469	467	—
Acquired during year	31	—	477
Amortization	—	—	(10)
Foreign currency translation	(27)	2	—
Closing balance at December 31	473	469	467

Effective January 1, 2002 goodwill ceased to be subject to amortization.

3. Inventories

December 31	2003	2002
Materials and supplies	95	143
Product	5	4
	100	147

4. Property, Plant and Equipment

December 31, 2003	Cost	Accumulated DD&A	Net book value
Oil and gas properties	10,426	4,774	5,652
Gas plants, pipelines and production equipment	5,860	1,813	4,047
Corporate assets	242	163	79
	16,528	6,750	9,778
December 31, 2002			
Oil and gas properties	10,198	4,264	5,934
Gas plants, pipelines and production equipment	5,576	1,547	4,029
Corporate assets	213	134	79
	15,987	5,945	10,042

In the year ended December 31, 2003, interest costs of \$24 million (2002 – \$25 million, 2001 – \$19 million) were capitalized.

Included in property, plant and equipment are the following costs that were not subject to depreciation, depletion or amortization ("DD&A") as at December 31:

Non-depleted capital at December 31	2003	2002
Acquired probable reserve costs ¹		
North America – associated with producing fields	140	102
North Sea – not associated with producing fields	14	13
Southeast Asia – not associated with producing fields	–	39
Exploration costs ²	283	353
Development projects ³		
Southeast Asia	265	437
North Sea	17	44
Algeria	39	175
Trinidad	108	30
	866	1,193

¹ Acquisition costs of probable reserves are not depleted or amortized while under active evaluation for commercial reserves.

² Exploration costs consist of drilling in progress and wells awaiting determination of proved reserves, approval of development plans or commencement of production.

³ Development projects are not depleted pending initial production.

The carrying values of property, plant and equipment, including acquired probable reserve costs, are subject to uncertainty associated with the quantity of oil and gas reserves, future production rates, commodity prices and other factors. Future events could result in material changes to the carrying values recognized in the Consolidated Financial Statements.

5. Long-Term Debt

December 31	2003	2002
Bank Credit Facilities ¹		
Bank Credit Facilities (2002 – 3.32%)	—	265
Debentures and Notes (Unsecured) ³		
6.625% notes (£250 million), due 2017 ⁵	471	576
7.25% debentures (US\$300 million), due 2027	388	474
5.80% medium term notes, due 2007	385	385
6.96% notes (US\$200 million), due 2005	258	316
7.125% debentures (US\$175 million), due 2007	226	276
5.70% medium term notes, due 2003	—	180
8.06% medium term notes, due 2009	174	174
6.68% notes (US\$100 million), due 2008	129	158
6.89% notes (US\$50 million), Series B, due 2006 ⁴	65	79
9.80% debentures, Series B, due 2004 ²	75	75
6.71% notes (US\$25 million), Series A, due 2004 ²	32	39
	2,203	2,997

1 Rates reflect the weighted-average interest rate of instruments outstanding at December 31. Rates are floating rate-based and vary with changes in short-term market interest rates.

2 The amounts outstanding at December 31, 2003 have been classified as long-term debt since the Company has the ability and intention to replace the current portions with long-term borrowings under the revolving bank credit facilities.

3 Interest on debentures and notes is payable semi-annually except for interest on the 6.625% notes (£250 million) which is payable annually.

4 Repayable in five equal annual installments commencing 2006.

5 The £250 million Eurobond has been effectively swapped into a US\$364 million indebtedness with floating interest payments based on three-month US LIBOR with an effective interest rate of 2.07% at December 31, 2003 (see note 9).

Bank Credit Facilities

Talisman has unsecured credit facilities totaling \$1,135 million, consisting of facilities of \$405 million ("Facility No. 1"), \$530 million ("Facility No. 2"), \$150 million ("Facility No. 3") and \$50 million ("Facility No. 4"). The maturity date of Facility No. 1 is March 23, 2006, although this date may be extended from time to time upon agreement between the Company and the respective lenders. Prior to the maturity date, the Company may borrow, repay and reborrow at its discretion. The term dates of Facility Nos. 2, 3 and 4 are March 16, 2004, August 23, 2004 and November 24, 2004, respectively. Until each term date, the Company may borrow, repay and reborrow at its discretion. Annually, upon agreement between the Company and the respective lenders, each term date may be extended for an additional 364 days. Facility No. 2 expires two years after its term date and, if the term is not extended, must be repaid on the maturity date. Facility Nos. 3 and 4 expire one year after their term dates and, if the terms are not extended, must be repaid on the maturity date.

Borrowings under Facility Nos. 1 and 2 are available in the form of prime loans, Canadian or US dollar bankers' acceptances, US dollar base rate loans or LIBOR-based loans. In addition, drawings to a total of \$467 million may be made by letters of credit. Borrowings under Facility No. 3 are available in the form of prime loans, Canadian or US dollar bankers' acceptances, US dollar base rate loans, LIBOR-based loans and letters of credit. Borrowings under Facility No. 4 are available in the form of prime loans, Canadian or US dollar guaranteed notes, US dollar base rate loans and LIBOR-based loans.

Repayment Schedule

The Company's contractual minimum repayments of long-term debt in the next five years are as follows:

Year	
2004 ¹	107
2005	258
2006	13
2007	624
2008	142
Subsequent to 2008	1,059
Total	2,203

1 The portion of long-term debt payable in 2004 has been classified as long-term debt since the Company has the ability and intention to replace the current portion with long-term borrowings under the revolving bank credit facilities.

6. Preferred Securities

During 1999, Talisman issued 12 million preferred securities ("securities") as unsecured junior subordinated debentures, at US\$25 per security, of which six million 9% securities are due February 15, 2048 and six million 8.9% securities are due June 15, 2048. The securities are redeemable, in whole or in part, at par by Talisman through the payment of cash or issuance of common shares at any time on or after February 15, 2004 and June 15, 2004, respectively. The Company has the option to defer the payment of the security charges for up to 20 consecutive three-month periods and satisfy such deferred security charges with either cash or the issuance of common shares. Security charges are due quarterly.

In December 2003, the Company announced its intention to exercise its right to redeem the outstanding six million 9% securities for US\$150 million. The difference between the carrying amount of the redeemed securities and the cost of the redemption will be credited directly to retained earnings.

7. Share Capital

Talisman's authorized share capital consists of an unlimited number of common shares without nominal or par value and first and second preferred shares. No preferred shares have been issued.

Continuity of common shares	2003		2002		2001	
	Shares	Amount	Shares	Amount	Shares	Amount
Balance, beginning of year	131,039,435	2,785	133,733,182	2,831	135,344,045	2,849
Issued on exercise of options	294,893	11	1,154,067	36	1,512,898	49
Purchased during year	(3,335,600)	(71)	(3,847,500)	(82)	(3,036,400)	(65)
Cancelled pursuant to terms of plans of arrangements	—	—	(314)	—	(87,361)	(2)
Balance, end of year	127,998,728	2,725	131,039,435	2,785	133,733,182	2,831

During the year ended December 31, 2003, Talisman repurchased 3,335,600 common shares of the Company pursuant to a normal course issuer bid for a total of \$194 million (2002 — \$220 million; 2001 — \$166 million). The cost to repurchase common shares in excess of their average book value has been charged to retained earnings, contributed surplus and cumulative foreign currency translation. In 2001, Talisman cancelled 87,361 common shares of the Company pursuant to the terms of the offering agreements of certain past corporate acquisitions. As a result of the cancellation of these shares, \$2 million was credited to contributed surplus. An additional 314 common shares were cancelled in 2002.

Stock Option Plans

Talisman has stock option plans that allow employees and directors to receive options to purchase common shares of the Company. Options granted under the plans are generally exercisable after three years and expire 10 years after the grant date. Option exercise prices approximate the market price for the common shares on the date the options are granted.

Effective 2003, the stock option plans were amended to provide option holders the choice upon exercise to receive a cash payment in exchange for surrendering the option. The cash payment is equal to the appreciated value of the stock option as determined based on the difference between the option's exercise price and the Company's share price at the time of surrender. As a result, in accordance with the accounting policy described in note 1(n), the Company's 2003 results included a \$105 million (\$74 million, or \$0.57/share, net of tax) stock-based compensation expense relating to the appreciated value of the Company's outstanding stock options and cash units at June 30, 2003. The total stock-based compensation expense for the year was \$185 million (\$130 million, net of tax) including \$80 million during the second half of 2003 due to the appreciation of the Company's stock price during the period July 1 to December 31. Additional stock-based compensation expense or recoveries in future periods is dependent on the movement of the Company's share price and the number of outstanding options and cash units.

The following table provides pro forma measures of net income and net income per common share had stock options been recognized as compensation expense based on the estimated fair value of the options on the grant date.

	2003	2002	2001
Net income as reported	1,007	524	733
Stock-based compensation expensed	105	—	—
Net income before stock-based compensation	1,112	524	733
Stock option expense based on fair market value	21	31	24
Pro forma net income ¹	1,091	493	709
Pro forma net income per share ¹			
Basic	8.31	3.50	5.08
Diluted	8.21	3.44	4.99

1 Pro forma net income and net income per share had stock options been recognized as compensation expense based on the estimated fair value of the options on the grant date.

Stock options granted in 2003 had an estimated weighted-average fair value of \$22.91 per option (2002 — \$26.19 per option; 2001 — \$22.80 per option). All options issued by the Company permit the holder to purchase one common share of the Company at the stated exercise price, or effective 2003, to receive a cash payment equal to the appreciated value of the stock option.

The estimated fair value of stock options issued was determined using the Black-Scholes model using the following weighted-average assumptions:

	2003	2002	2001
Risk-free interest rate (%)	4.1	5.1	4.9
Estimated hold period prior to exercise (years)	5.3	5.4	5.3
Volatility in the price of the Company's common shares (%)	40	41	39
Dividends (\$/share)	0.60	0.60	0.60

Continuity of stock options	2003		2002		2001	
	Number of Options	Average Exercise Price	Number of Options	Average Exercise Price	Number of Options	Average Exercise Price
Outstanding at January 1	7,384,054	46.53	7,497,611	41.49	6,854,806	33.84
Granted	2,394,699	59.48	1,100,710	64.73	2,301,828	58.39
Exercised for common shares	294,893	33.81	1,154,067	30.54	1,512,898	32.19
Exercised for cash payment	1,420,237	35.51	—	—	—	—
Forfeited	196,540	58.88	59,150	57.53	146,125	45.24
Expired	551	30.53	1,050	57.88	—	—
Outstanding at December 31	7,866,532	52.64	7,384,054	46.53	7,497,611	41.49
Exercisable at December 31	2,580,955	37.38	3,142,629	34.34	3,246,985	35.87
Options available for future grants pursuant to the Company's Stock Option Plans	4,678,518		3,155,889		4,196,399	

The range of exercise prices of the Company's outstanding stock options is as follows:

December 31, 2003	Outstanding Options			Exercisable Options	
	Number of Options	Weighted Average Exercise Price	Weighted Average Years to Expiry	Number of Options	Weighted Average Exercise Price
Range of Exercise Prices					
\$24.25 to \$29.99	672,555	25.62	4	672,555	25.62
\$30.00 to \$39.99	814,305	36.80	5	814,305	36.80
\$40.00 to \$49.99	932,000	42.25	4	932,000	42.25
\$50.00 to \$59.99	4,262,362	58.88	8	92,145	58.24
\$60.00 to \$68.36	1,185,310	64.55	8	69,950	64.73
\$24.25 to \$68.36	7,866,532	52.64	7	2,580,955	37.38

At December 31, 2003, 12,545,050 common shares were reserved for issuance related to the stock option plans.

Cash Units

In addition to the Company's stock option plans, Talisman's subsidiaries during 2003 issued 384,505 cash units with an average exercise price of \$59.48/cash unit to certain employees. Cash units are similar to stock options except that the holder does not have a right to purchase the underlying share of the Company.

8. Cumulative Foreign Currency Translation

In accordance with the Company's foreign exchange translation accounting policy, as disclosed in note 1(i), foreign exchange gains or losses on translation of self-sustaining operations and the translation of the Company's financial results into Canadian dollars for reporting purposes are included in shareholders' equity in the cumulative foreign currency translation account.

The following components give rise to the exchange gains or (losses) included in the cumulative foreign currency translation account as at December 31:

	2003	2002
Property, plant and equipment	(443)	220
Future tax liabilities (including PRT)	37	(47)
Provision for site restoration	(4)	(71)
Long-term debt	341	13
Working capital	(20)	23
Goodwill	(25)	2
	(114)	140

9. Financial Instruments

Financial contracts

The Company entered into natural gas and crude oil price derivative contracts to reduce the volatility of the Company's cash flows associated with anticipated natural gas and crude oil sales. The amounts shown below are the weighted-average of the contracts outstanding.

Natural gas derivative contracts

	2004	Two-way collars (AECO)	2004
Fixed price swaps (NYMEX)			
Volumes (mcf/d)	48,400	Volumes (mcf/d)	6,900
Price (\$/mcf)	5.91	Ceiling (\$/mcf)	9.55
		Floor (\$/mcf)	6.81

Crude oil derivative contracts

	2004	2005	Two-way collars	2004
Fixed price swaps				
(WTI oil index)			(WTI oil index)	
Volumes (bbls/d)	12,000	6,000	Volumes (bbls/d)	25,000
Price (US\$/bbl)	29.20	26.97	Ceiling price (US\$/bbl)	28.90
			Floor price (US\$/bbl)	25.08
(Brent oil index)			(Brent oil index)	
Volumes (bbls/d)	11,000		Volumes (bbls/d)	31,000
Price (US\$/bbl)	26.08		Ceiling price (US\$/bbl)	26.61
			Floor price (US\$/bbl)	23.56

Interest rates

In December 1994, in anticipation of issuing the US\$175 million 7.125% debentures, Talisman entered into interest rate swap contracts to hedge against possible adverse interest rate fluctuations. These contracts result in Talisman paying interest at a rate of 8.295% in exchange for receiving the three-month LIBOR rate on notional principal of US\$100 million until May 16, 2005. Based on the LIBOR rate at December 31, 2003, these contracts result in an effective rate of interest on the debentures of 11.2%. Effective January 1, 2004 these contracts are no longer designated as hedges of the debentures. The accumulative loss on these contracts at December 31, 2003 will be deferred and amortized into income over their remaining term.

Cross currency and interest rate swaps

The Company had designated its US dollar cross currency and interest rate swap contracts outstanding during 2003 as hedges of the £250 million Eurobond. This in effect converted the Eurobond to US\$364 million with a floating interest rate based on three-month US LIBOR. Effective January 1, 2004, these swap contracts are no longer designated as hedges of the Eurobond. The accumulative gain on these contracts at December 31, 2003 will be deferred and amortized into income over the original term of the swap contracts. Subsequent to year end, the Company terminated contracts totaling a nominal amount of £190 million for proceeds of \$108 million. The remaining contracts expire December 5, 2009.

Carrying Amounts and Estimated Fair Values of Financial Instruments

Asset (liability) at December 31	2003			2002		
	Carrying Value	Fair Value	Unrecognized	Carrying Value	Fair Value	Unrecognized
Debentures and notes	(2,203)	(2,535)	(332)	(2,732)	(3,006)	(274)
Forward foreign currency swaps	—	—	—	—	14	14
Cross currency and interest rate swaps	—	110	110	—	72	72
Natural gas derivatives	—	(21)	(21)	—	(10)	(10)
Crude oil derivatives	—	(81)	(81)	—	(52)	(52)

Borrowings under bank credit facilities are for short terms and are market rate based, thus, carrying values approximate fair value. The fair value of debentures and notes is based on market quotations, which reflect the discounted present value of the principal and interest payments using the effective yield at December 31 for instruments having the same term and risk characteristics. Fair values for derivative instruments are determined based on the estimated cash payment or receipt necessary to settle the contract at December 31. Cash payments or receipts are based on discounted cash flow analysis using current market rates and prices.

The fair values of other financial instruments, including cash and cash equivalents, accounts receivable, accounts payable and income and other taxes payable, approximate their carrying values.

Credit Risk

A significant portion of the Company's accounts receivable is due from entities in the oil and gas industry. Concentration of credit risk is mitigated by having a broad domestic and international customer base, which includes a significant number of companies engaged in joint operations with Talisman. The Company routinely assesses the financial strength of its partners and customers, including parties involved in marketing or other commodity arrangements. The Company's largest credit exposure to a single party is approximately \$60 million.

The Company is exposed to credit risk associated with possible non-performance by derivative instrument counterparties. The Company actively limits the total exposure to individual counterparties.

10. Contingencies and Commitments

From time to time, Talisman is the subject of litigation arising out of the Company's operations. These claims, including the lawsuit discussed below, are not currently expected to have a material impact on the Company's financial position.

Talisman is subject to a lawsuit brought by the Presbyterian Church of Sudan and others under the Alien Tort Claims Act in the United States District Court for the Southern District of New York. The lawsuit, which is seeking class action status, alleges that the Company conspired with, or aided and abetted, the Government of Sudan to commit violations of international law in connection with the Company's now disposed of indirect interest in oil operations in Sudan. In July 2003, Talisman filed a motion to dismiss the lawsuit for lack of personal jurisdiction of the Court over Talisman. In August 2003, the plaintiffs filed a motion seeking certification of the case as a class action. Talisman is in the process of challenging this certification. No decision is expected on either of these motions prior to the third quarter of 2004. Talisman believes these claims to be entirely without merit and is continuing to vigorously defend itself against this lawsuit and does not expect this to have a material adverse effect.

Talisman's estimated total undiscounted future dismantlement, site restoration and abandonment liability at December 31, 2003 was \$2.0 billion (2002 – \$1.7 billion), approximately 80% of which is denominated in UK Pounds Sterling. At December 31, 2003, Talisman had accrued \$840 million (2002 – \$813 million) of this liability. Estimated future dismantlement, site restoration and abandonment costs and the related provision in the Consolidated Financial Statements are subject to uncertainty associated with the method, timing and extent of future dismantlement, site restoration and abandonment. For example, changes in legislation or technology may result in actual future costs that differ materially from those estimated. The Company has provided letters of credit in 2004 in the amount of \$547 million of which a majority were provided as security for the costs of future dismantlement, site restoration and abandonment obligations in the North Sea (\$472 million). The remaining outstanding letters of credit primarily relate to a retirement compensation arrangement and the guarantee of a minimum work commitment.

Talisman has firm commitments for gathering, processing and transportation services that require the Company to pay tariffs to third parties for processing or shipment of certain minimum quantities of crude oil and liquids and natural gas. The Company has sufficient production to meet these commitments.

Talisman leases certain of its ocean-going vessels and corporate offices, all of which are accounted for as operating leases. The term of the Ross Floating Production, Storage and Offloading vessel ("FPSO") lease depends on the expected life of the Ross and Blake fields. A lease for an FPSO contracted in Malaysia expires in 2004. In addition, Talisman has ongoing operating commitments associated with the vessels.

Estimated future minimum commitments¹

	2004	2005	2006	2007	2008	Subsequent to 2008	Total
Office leases	19	16	16	16	16	113	196
Vessel leases	95	—	—	—	—	—	95
Transportation and processing commitments ²	135	99	82	76	70	617	1,079
Minimum work commitments	203	47	30	21	7	—	308
Abandonment obligations	9	9	25	80	12	1,883	2,018
Other service contracts	19	16	16	5	4	71	131
Total	480	187	169	198	109	2,684	3,827

1 Future minimum payments denominated in foreign currencies have been translated into Canadian dollars based on the December 31, 2003 exchange rate.

2 Certain of the Company's transportation commitments are tied to firm gas sales contracts.

The Company has entered into sales contracts for a portion of its future North American natural gas production. The following are the average volumes under contract and the weighted-average contract price in each of the years shown.

Fixed price sales	2004	2005	2006	Three-way collars	2004
Volumes (mcf/d)	40,250	14,650	14,650	Volumes (mcf/d)	15,300
Average price (\$/mcf)	3.89	3.29	3.29	Call strike (\$/mcf)	3.49
				Put strike (\$/mcf)	3.32
				Sold put strike (\$/mcf)	2.67

The three-way collars are similar to two-way commodity collars with the call and put strike prices being equivalent to the ceiling and floor prices, except that should the NIT (Nova Inventory Transfer) index fall below the sold put strike price, Talisman will receive NIT plus the difference between the put strike and sold put strike prices.

11. Other Revenue

Years ended December 31	2003	2002	2001
Pipeline and custom treating tariffs	63	69	63
Investment income	9	8	15
Marketing income	4	3	4
	76	80	82

12. Other Expenses (Income)

Years ended December 31	2003	2002	2001
Net loss (gain) on asset disposals	(14)	10	(11)
Foreign exchange losses	7	28	51
Project loan facility deferred costs write-off	—	—	17
Property impairments	30	74	—
Other expense (income)	(7)	1	21
	16	113	78

13. Taxes

Income Taxes

The current and future income taxes for each of the three years ended December 31 are as follows:

	2003	2002	2001
Current income taxes (recovery)			
North America ¹	21	(20)	45
North Sea	99	131	162
Southeast Asia	84	76	83
Sudan	17	68	50
Other	8	3	2
	229	258	342
Future income taxes (recovery)			
North America ¹	(49)	67	134
North Sea	22	116	(69)
Southeast Asia	(13)	(3)	15
Algeria	4	—	—
Sudan	9	16	3
Other	(24)	(34)	(11)
	(51)	162	72
Income taxes	178	420	414

1 Current North America income taxes include the Canadian federal tax on large corporations, net of Alberta royalty tax credits.

The components of the net future tax liability at December 31, are as follows:

	2003	2002
Future tax liabilities		
Property, plant and equipment	2,251	2,392
Pension assets	22	21
Other	216	184
	2,489	2,597
Future tax assets		
Provision for future site restoration	332	297
Other	69	64
	401	361
Net future tax liability	2,088	2,236

Future distribution taxes associated with operations in the UK have not been recorded because, based on current plans, repatriation of funds in excess of foreign reinvestment will not result in material amounts of tax expense. Unremitted earnings in other foreign jurisdictions are not material.

Income taxes vary from the amount that would be computed by applying the Canadian statutory income tax rate of 35.36% for the year ended December 31, 2003 (2002 – 42.08%; 2001 – 42.45%) as follows:

Years ended December 31	2003	2002	2001
Income taxes calculated at the Canadian statutory rate	451	442	572
Increase (decrease) in income taxes resulting from:			
Non-deductible royalties, mineral taxes and expenses	158	138	207
Resource allowances	(122)	(128)	(168)
Change in statutory tax rates	(160)	116	(34)
Non-taxable income	(80)	—	—
Deductible PRT expense	(32)	(51)	(62)
Lower foreign tax rates (net)	(2)	(80)	(90)
Provincial rebates and credits	(12)	(10)	(40)
Federal tax on large corporations	10	9	9
Other	(33)	(16)	20
Income taxes	178	420	414

Petroleum Revenue Tax

Petroleum Revenue Tax (PRT) expense primarily relates to the UK and is comprised of current tax expense of \$72 million (2002 – \$91 million; 2001 – \$102 million) and deferred tax expense of \$20 million (2002 – \$33 million; 2001 – \$47 million). The measurement of PRT expense and the related provision in the Consolidated Financial Statements is subject to uncertainty associated with future recovery of oil and gas reserves, commodity prices and the timing of future events, which could result in material changes to deferred amounts.

14. Consolidated Statements of Cash Flows

Selected cash flow information:

Years ended December 31	2003	2002	2001
Net income	1,007	524	733
Items not involving current cash flow			
Depreciation, depletion and amortization	1,443	1,495	1,313
Property impairments	30	74	—
Dry hole	251	174	113
Net loss (gain) on asset disposals	(14)	10	(11)
Gain on sale of Sudan	(296)	—	—
Stock-based compensation	138	—	—
Future taxes and deferred PRT	(32)	195	119
Other	(11)	(12)	80
	1,509	1,936	1,614
Exploration	213	185	147
Cash flow	2,729	2,645	2,494
Cash interest paid (net of capitalized interest)	139	156	137
Cash income taxes paid	168	274	365

Changes in operating non-cash working capital consisted of the following:

Years ended December 31	2003	2002	2001
Accounts receivable	(32)	(155)	266
Inventories	32	(42)	10
Prepaid expenses	4	5	(9)
Accounts payable and accrued liabilities	(63)	(16)	(323)
Income and other taxes payable	(45)	45	(121)
Net use of cash	(104)	(163)	(177)

15. Net Income and Diluted Net Income Per Share

The following table summarizes the calculation of net income and diluted net income per share.

	2003	2002	2001
Net income	1,007	524	733
Less preferred security charges, net of tax	22	24	24
Net income available to common shareholders	985	500	709
Weighted average number of common shares outstanding (millions) – basic	129	134	135
Dilution effect of stock options (millions)	1	2	2
Weighted average number of commons shares outstanding (millions) – diluted	130	136	137
Net income per share (\$/share)			
Basic	7.65	3.73	5.25
Diluted	7.57	3.67	5.16

Outstanding stock options are the only instruments that are currently dilutive to earnings per share. For 2003, 1,168,210 stock options that were antidilutive have been excluded from the computation of diluted earnings per share (2002 – 1,080,035; 2001 – 2,249,145).

16. Employee Benefits

The Company sponsors both defined benefit and defined contribution pension arrangements covering substantially all employees. The Company uses actuarial reports prepared by independent actuaries for funding and accounting purposes. The Company uses a December 31 measurement date for the majority of its defined benefit pension plans. The following significant actuarial assumptions were employed to determine the periodic pension expense and the accrued benefit obligations:

	2003	2002	2001
Expected long-term rate of return on plan assets (%)	7.5	7.5	7.5
Discount rate (%)	6.4	6.5	6.5
Rate of compensation increase (%)	4.5	4.5	4.5

The Company's net benefit plan expense (credit) is as follows:

	2003	2002	2001
Current service cost – defined benefit	7	5	2
Current service cost – defined contribution	7	6	5
Interest cost	8	7	5
Expected return on plan assets	(9)	(11)	(10)
Amortization of net transitional asset	(1)	(1)	(1)
Amortization of actuarial losses	2	—	—
Net benefit plan expense	14	6	1

Information about the Company's defined benefit pension plans is as follows:

	2003		2002	
	Pension plans grouped by funded status		Pension plans grouped by funded status	
	Surplus	Deficit ¹	Surplus	Deficit ¹
Accrued benefit obligation				
Accrued benefit obligation, beginning of year	54	63	53	42
Current service cost	1	6	1	4
Interest cost	4	4	3	3
Actuarial losses	7	8	1	14
Plan participants' contributions	—	1	—	1
Benefits paid	(4)	(4)	(4)	(1)
Accrued benefit obligation, end of year	62	78	54	63
Plan assets				
Fair value of plan assets, beginning of year	114	21	128	21
Actual gain (loss) on plan assets	14	3	(4)	(5)
Employer contributions	—	8	—	5
Plan participants' contributions	—	1	—	1
Surplus applied to defined contribution plan	(7)	—	(6)	—
Benefits paid	(4)	(4)	(4)	(1)
Fair value of plan assets, end of year	117	29	114	21
Funded status — surplus (deficit)	55	(49)	60	(42)
Unamortized net actuarial loss	19	26	18	21
Unamortized net transitional (asset) obligation	(11)	3	(11)	2
Net accrued benefit asset (liability)	63	(20)	67	(19)

¹ The net accrued benefit liability for pension plans with a deficit funding status is included in deferred credits on the Consolidated Balance Sheet.

At December 31, 2003, the actuarial net present value of the accrued benefit obligation for other post-retirement benefit plans was \$8 million (2002 — \$7 million).

The net benefit plan expense of \$14 million for the year ended December 31, 2003 (2002— \$6 million; 2001 — \$1 million) is determined by using actuarial assumptions including expected return on plan assets and includes the amortization of net actuarial losses and net transitional assets and obligations as described in note 1(j). Had the net benefit expense for the year been calculated without deferring and amortizing net actuarial losses and net transitional assets and obligations, the net benefit expense for 2003 would have been \$12 million (2002 — \$37 million; 2001 — \$23 million).

At December 31, 2003, the composition of plan assets as a percentage of fair value was 70% equities and 30% bonds. The approximate target allocation percentage is 70% equities, 30% bonds and expected return on assets is 8.5% equities and 5.3% bonds.

17. Sale of Sudan Operations

On March 12, 2003, the Company completed the sale of its 25% indirectly held interest in the Greater Nile Oil Project in Sudan. Total gross proceeds were \$1.13 billion (US\$771 million), including interest and cash received by Talisman during the interim period between September 1, 2002 and closing on March 12, 2003. The gain on sale is as follows:

Gross proceeds on sale of Sudan operations (US\$771 million)	1,135
Less interim adjustments	(123)
	1,012
Property, plant and equipment	687
Working capital and other assets	72
Future income tax liability	(59)
Net carrying value at March 12, 2003	700
Closing costs	16
Gain on disposal	296

18. Segmented Information

Talisman's activities are conducted in five geographic segments: North America, the North Sea, Southeast Asia, Algeria and other international locations. The Sudan operations were sold in 2003. North America includes operations in Canada and the US. The North Sea includes operations in the UK, Netherlands and Norway. The Southeast Asia segment includes operations in Indonesia, Malaysia and Vietnam. All activities relate to the exploration, development, production and transportation of oil, liquids and natural gas.

	North America ²			North Sea ³		
	2003	2002	2001	2003	2002	2001
Revenue						
Gross sales						
Oil and liquids	683	706	714	1,556	1,798	1,466
Natural gas	1,972	1,270	1,583	182	173	172
Synthetic oil	42	42	40	—	—	—
Sulphur	6	(4)	(5)	—	—	—
Total gross sales	2,703	2,014	2,332	1,738	1,971	1,638
Royalties	587	373	558	8	96	93
Net sales	2,116	1,641	1,774	1,730	1,875	1,545
Other	54	38	34	23	40	46
Total revenue	2,170	1,679	1,808	1,753	1,915	1,591
Segmented expenses						
Operating						
Oil and liquids	131	121	121	523	517	407
Natural gas	237	212	198	21	27	18
Synthetic oil	22	19	20	—	—	—
Pipeline	5	5	4	39	44	42
Total operating expenses	395	357	343	583	588	467
DD&A	693	614	585	619	701	558
Dry hole	135	128	54	69	9	21
Exploration	87	66	69	21	20	30
Other	(28)	77	11	26	55	(23)
Total segmented expenses	1,282	1,242	1,062	1,318	1,373	1,053
Segmented income (loss) before taxes	888	437	746	435	542	538
Non-segmented expenses						
General and administrative						
Interest on long-term debt						
Gain on sale of Sudan operation						
Stock based compensation						
Currency translation						
Total non-segmented expenses						
Income before taxes						
Capital expenditures						
Exploration	453	321	314	99	134	106
Development	629	480	535	397	297	527
Midstream	27	21	27	—	—	—
Exploration and development	1,109	822	876	496	431	633
Property acquisitions ¹						
Midstream acquisitions						
Proceeds on dispositions						
Other non-segmented						
Net capital expenditures						
Property, plant and equipment	5,642	4,955	4,773	2,710	2,921	2,831
Goodwill	291	291	291	74	46	41
Other	403	350	265	386	387	371
Segmented assets	6,336	5,596	5,329	3,170	3,354	3,243
Non-segmented assets						
Total assets						

1 Excluding corporate acquisitions.

North America		2003	2002	2001
Revenues	Canada	2,018	1,674	1,808
	US	152	5	—
		2,170	1,679	1,808
Property, plant and equipment	Canada	5,238	4,848	4,769
	US	404	107	4
		5,642	4,955	4,773

North Sea		2003	2002	2001
Revenues	UK	1,691	1,888	1,561
	Netherlands	26	27	30
	Norway	36	—	—
		1,753	1,915	1,591
Property, plant and equipment	UK	2,555	2,875	2,791
	Netherlands	39	46	40
	Norway	116	—	—
		2,710	2,921	2,831

Southeast Asia ⁴			Algeria			Sudan			Other			Total ⁵		
2003	2002	2001	2003	2002	2001	2003	2002	2001	2003	2002	2001	2003	2002	2001
345	323	276	89	—	—	209	828	638	—	—	—	2,882	3,655	3,094
211	163	163	—	—	—	—	—	—	—	—	—	2,365	1,606	1,918
—	—	—	—	—	—	—	—	—	—	—	—	42	42	40
—	—	—	—	—	—	—	—	—	—	—	—	6	(4)	(5)
556	486	439	89	—	—	209	828	638	—	—	—	5,295	5,299	5,047
156	130	90	46	—	—	97	328	248	—	—	—	894	927	989
400	356	349	43	—	—	112	500	390	—	—	—	4,401	4,372	4,058
—	1	1	—	—	—	(1)	1	1	—	—	—	76	80	82
400	357	350	43	—	—	111	501	391	—	—	—	4,477	4,452	4,140
65	65	54	16	—	—	18	84	66	—	—	—	753	787	648
22	21	16	—	—	—	—	—	—	—	—	—	280	260	232
—	—	—	—	—	—	—	—	—	—	—	—	22	19	20
—	—	—	—	—	—	—	—	—	—	—	—	44	49	46
87	86	70	16	—	—	18	84	66	—	—	—	1,099	1,115	946
95	87	93	17	—	—	19	93	77	—	—	—	1,443	1,495	1,313
9	4	8	1	—	5	—	13	16	37	20	9	251	174	113
17	19	8	—	5	2	5	6	11	83	69	27	213	185	147
9	11	(2)	—	2	8	—	(5)	11	2	(9)	—	9	131	5
217	207	177	34	7	15	42	191	181	122	80	36	3,015	3,100	2,524
183	150	173	9	(7)	(15)	69	310	210	(122)	(80)	(36)	1,462	1,352	1,616
												152	138	108
												137	164	139
												(296)	—	—
												185	—	—
												7	(18)	73
												185	284	320
												1,277	1,068	1,296
70	36	31	4	4	22	7	27	42	151	106	52	784	628	567
246	233	110	30	103	40	(5)	71	75	72	15	1	1,369	1,199	1,288
—	—	—	—	—	—	—	—	—	—	—	—	27	21	27
316	269	141	34	107	62	2	98	117	223	121	53	2,180	1,848	1,882
												638	276	301
												130	—	—
												(100)	(72)	(162)
												38	26	30
												2,886	2,078	2,051
1,079	1,093	924	202	244	143	—	772	767	145	57	23	9,778	10,042	9,461
108	132	135	—	—	—	—	—	—	—	—	—	473	469	467
217	205	137	27	6	4	—	56	44	18	12	3	1,051	1,016	824
1,404	1,430	1,196	229	250	147	—	828	811	163	69	26	11,302	11,527	10,752
												63	67	67
												11,365	11,594	10,819

4	Southeast Asia	2003	2002	2001
	Revenues			
	Indonesia	304	302	332
	Malaysia	85	50	18
	Vietnam	11	5	—
		400	357	350
	Property, plant and equipment			
	Indonesia	383	515	508
	Malaysia	673	565	407
	Vietnam	23	13	9
		1,079	1,093	924

5 Certain comparative segmented disclosures have been reclassified to be consistent with the current year presentation.

19. Information for US Readers

Accounting Principles Generally Accepted in the US

The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP") which, in most respects, conform to accounting principles generally accepted in the United States ("US GAAP"). Significant differences between Canadian and US GAAP are as follows:

Net income in accordance with US GAAP:

Years ended December 31

(millions of Canadian dollars)

	Notes	2003	2002	2001
Net income – Canadian GAAP		1,007	524	733
Foreign exchange loss	4,6	(62)	(56)	(44)
Depreciation, depletion and amortization	1,2,3,6,8,9	45	(26)	(66)
(Loss) gain on derivative instruments	4	(17)	(129)	237
Preferred security charges	6	(38)	(42)	(42)
Deferred income taxes	2	15	51	(95)
Gain on sale of Sudan operations	8	(296)	–	–
ARO Accretion	9	(58)	–	–
Results of discontinued operations, net of tax	8	(57)	(237)	(157)
		(468)	(439)	(167)
Income from continuing operations		539	85	566
Results of discontinued operations, net of tax	8	330	237	157
Income before cumulative effect of changes in accounting principles		869	322	723
Cumulative effect of changes in accounting principles, net of tax	4,9	53	–	(48)
Net income – US GAAP		922	322	675
Income per common share (Canadian dollars)				
Basic				
Continuing operations		4.19	0.64	4.20
Discontinued operations		2.56	1.76	1.16
Before cumulative effect of changes in accounting principles		6.75	2.40	5.36
Cumulative effect of changes in accounting principles, net of tax		0.41	–	(0.36)
Net income		7.16	2.40	5.00
Diluted				
Continuing operations		4.14	0.63	4.12
Discontinued operations		2.53	1.74	1.14
Before cumulative effect of changes in accounting principles		6.67	2.37	5.26
Cumulative effect of changes in accounting principles, net of tax		0.41	–	(0.35)
Net income		7.08	2.37	4.91

Comprehensive income in accordance with US GAAP:

Years ended December 31

(millions of Canadian dollars)

	Notes	2003	2002	2001
Net income – US GAAP		922	322	675
Other comprehensive income, net of tax:				
Foreign exchange gain on translation of self-sustaining operations	7	650	170	—
Comprehensive income – US GAAP		1,572	492	675

Balance sheet items in accordance with US GAAP are as follows:

December 31

(millions of Canadian dollars)

	Notes	2003		2002	
		Canadian GAAP	US GAAP	Canadian GAAP	US GAAP
Current assets	8	975	975	917	861
Sudan assets held for sale	8	—	—	—	842
Property, plant and equipment	1,2,3,8,9	9,778	10,531	10,042	9,653
Other non-current assets	4,6	612	607	635	651
		11,365	12,113	11,594	12,007
Current liabilities	8	1,218	1,218	989	960
Sudan liabilities held for sale	8	—	—	—	87
Long-term debt	4,6	2,203	2,696	2,997	3,530
Future income taxes	2,8,9	2,088	2,062	2,236	2,127
Other non-current liabilities	9	897	1,208	870	870
		6,406	7,184	7,092	7,574
Shareholders' equity					
Preferred securities	6	431	—	431	—
Common shares		2,725	2,725	2,785	2,785
Contributed surplus	5	73	90	75	92
Cumulative foreign currency translation	4,6,7	(114)	(832)	140	(30)
Accumulative other comprehensive income	7	—	820	—	170
Retained earnings	1-9	1,844	2,126	1,071	1,416
Total liabilities and shareholders' equity		11,365	12,113	11,594	12,007

- Gains on property exchanges** — Under both US and Canadian GAAP, property exchanges are recorded at the carrying value of the assets given up unless the exchange transaction includes significant cash consideration, in which case it is recorded at fair value. Under US GAAP, asset exchange transactions are recorded at fair value if cash consideration is greater than 25% (10% under Canadian GAAP) of the fair value of total consideration given or received. The resulting differences in the recorded carrying values of these properties result in differences in depreciation, depletion and amortization expense in subsequent years.
- Income taxes and depreciation, depletion and amortization expense** — In 2000, the Company adopted the liability method to account for income taxes. The change to the liability method has eliminated a difference between Canadian and US GAAP, however, in accordance with the recommendations of the Canadian Institute of Chartered Accountants (the "CICA") the effect of the adoption under Canadian GAAP resulted in a charge to retained earnings, whereas, under US GAAP the future tax costs that gave rise to the Canadian GAAP adjustment have already been reflected in property, plant and equipment. As a result of the implementation method, further differences in depreciation, depletion and amortization expense result in subsequent years. Other adjustments to the Canadian GAAP net income required under US GAAP, as described in this note, have been tax effected as necessary.

- 3 Impairments** — Under both US and Canadian GAAP, property, plant and equipment must be assessed for potential impairments. Under US GAAP, if the sum of the expected future cash flows (undiscounted and without interest charges) is less than the carrying amount of the asset, then an impairment loss (the amount by which the carrying amount of the asset exceeds the fair value of the asset) should be recognized. Fair value is calculated as the present value of estimated expected future cash flows. As disclosed in note 1(c), under Canadian GAAP, the impairment loss is the difference between the carrying value of the asset and its net recoverable amount (undiscounted). The resulting differences in recorded carrying values of impaired assets result in further differences in depreciation, depletion and amortization expense in subsequent years. The CICA has adopted a new standard effective for 2004 that will eliminate this US/Canadian GAAP difference.
- 4 Forward foreign exchange contracts and other financial instruments** — The Company has designated, for Canadian GAAP purposes, its derivative financial instruments as hedges of anticipated revenue and expenses. In accordance with Canadian GAAP, payments or receipts on these contracts are recognized in income concurrently with the hedged transaction. The fair values of the contracts deemed to be hedges are not reflected in the Consolidated Financial Statements.
- Effective January 1, 2001, for US GAAP purposes, the Company adopted Statement of Financial Accounting Standards ("SFAS") No. 133, as amended, Accounting for Derivative Instruments and Hedging Activities. Effective with the adoption of this standard, every derivative instrument, including certain derivative instruments embedded in other contracts, is recognized on the balance sheet at fair value. The statement requires that changes in the derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met.
- Management has not designated any of the currently held derivative instruments as hedges for US GAAP purposes and accordingly these derivatives have been recognized on the balance sheet at fair value with the change in their fair value recognized in earnings. In accordance with the transition provisions of SFAS No. 133, on January 1, 2001, the Company recorded a \$48 million after-tax non-cash loss in current earnings as a cumulative effect of accounting change.
- 5 Appropriation of contributed surplus** — In 1992, concurrent with a change in control of the Company, \$17 million of contributed surplus was appropriated to retained earnings to eliminate the deficit at June 30, 1992. This restatement of retained earnings is not permitted under US GAAP as the events that precipitated it did not constitute a quasi-reorganization.
- 6 Preferred securities** — Under US GAAP, the Company's preferred securities are treated as debt rather than equity and accordingly are translated at the rates of exchange in effect at the balance sheet date. Under Canadian GAAP, the preferred securities are translated at the historical rate of exchange. In addition, the annual preferred security charges under US GAAP are classified as an expense rather than a direct charge to retained earnings. Under US GAAP, the cost associated with the issuance of the preferred securities is recorded as an asset and is amortized over the term of the preferred securities. Under Canadian GAAP, this cost, net of tax, is charged directly to shareholders' equity. The fair market value of the preferred securities at December 31, 2003 was \$389 million (2002 — \$494 million).
- 7 Foreign exchange gains and losses on translation of self sustaining operations** — Under US GAAP, foreign exchange gains and losses on translation of self-sustaining foreign operations are added, net of tax, to net income in determining comprehensive income. Under Canadian GAAP, such gains and losses are included as a separate component of shareholders' equity referred to as cumulative translation adjustment.
- 8 Discontinued operations** — Under US GAAP, effective November 1, 2002, the Sudan assets were classified as Assets Held For Sale with the Sudan operating results, net of tax, classified on the income statement as results of operations held for sale. No depreciation, depletion or amortization has been recorded commencing November 1, 2002 related to these assets. The sale closed March 12, 2003.
- 9 Asset Retirement Obligations (future site restoration and abandonment liabilities)** — Effective January 1, 2003, for US GAAP purposes, the Company adopted SFAS No. 143, which changes the method of accruing for costs associated with the retirement of fixed assets which an entity is legally obligated to incur. The standard requires entities to record the fair value of a liability for an asset retirement obligation in the period it is incurred and a corresponding increase in the carrying amount of the related long-lived asset.

The majority of the Company's asset retirement obligations relate to the abandoning of oil and gas wells, pipelines, processing facilities and offshore production platforms. During 2003, the Company's asset retirement obligation changed as follows.

(millions of Canadian dollars)

ARO liability at January 1, 2003	1,123
Liabilities incurred during year	97
Liabilities settled during year	(28)
Accretion expense	58
Foreign currency translation	(99)
ARO liability at December 31, 2003	1,151

SFAS No. 143 calls for the ARO liability to include as a component of expected costs, an estimate of the price that a third party would demand and could expect to receive, for bearing the uncertainty inherent in the obligations. This is referred to as the market-risk premium. No amount of market-risk premium has been included in the estimate of the Company's ARO liability as management does not believe there to be sufficient evidence in the oil and gas industry to estimate any such market premium.

The following table presents the pro forma effects of the retroactive application of this change in accounting principle. There was no pro forma effect on income from discontinued operations.

	2003	2002	2001
Pro forma net income ¹	869	342	665
Pro forma per common share			
Basic	6.75	2.55	4.93
Diluted	6.67	2.51	4.84

1 Pro forma net income for 2003 has been adjusted to remove the \$53 million cumulative effect of a change in accounting principle attributable to SFAS No. 143.

Newly Issued US Accounting Standards

Variable Interest Entities

In 2003, the Financial Accounting Standards Board (FASB) issued Interpretation No. 46 Consolidation of Variable Interest Entities (FIN 46), which is effective January 1, 2004. The Canadian Institute of Chartered Accountants (CICA) issued a similar accounting guideline (AcG 15). FIN 46 and AcG 15 provide guidance as to when a company should consolidate another entity into its Consolidated Financial Statements. A variable interest entity (VIE) is a corporation, partnership, trust, or any other legal structure used for business purposes that either (i) does not have equity investors with voting rights or (ii) has equity investors that do not provide sufficient financial resources for the entity to support its activities. FIN 46 and AcG 15 require a VIE to be consolidated by a company if that company is subject to a majority of the risk of loss from the VIE's activities, is entitled to receive a majority of the VIE's residual returns, or both. If a company has previously consolidated a VIE but is not subject to a majority of the risk of loss of its activities nor entitled to receive a majority of its residual returns, such a VIE is required to be deconsolidated. Management is currently evaluating the potential impact of FIN 46 and AcG 15 but does not expect their application to have a significant impact on the Company's financial position, operating results or cash flows.

Oil and Gas Drilling Rights

Talisman has classified all of its mineral drilling rights as oil and gas properties under the heading property, plant and equipment. Management believes this treatment is consistent with industry practice and management's understanding of the relevant accounting standards. It is management's understanding that the Staff of the Securities and Exchange Commission (SEC) is questioning registrants regarding the appropriateness of this accounting treatment, specifically as to whether these costs should be classified as intangible assets on the balance sheet separate from other property, plant and equipment. Further, it is management's understanding that this issue is being considered by the US Financial Accounting Standards Board (FASB). Management believes resolution of this issue will not materially affect the Company's results of operations.

Summary US Dollar Information

Unless otherwise noted, all amounts in the Consolidated Financial Statements, including Accounting Principles Generally Accepted in the United States above, are reported in millions of Canadian dollars. The following information reflects summary financial information prepared in accordance with US GAAP translated from Canadian dollars to US dollars at the average exchange rate prevailing in the respective year.

US\$ million (except as noted)	2003	2002	2001
Total revenue	3,194	2,835	2,673
Net income	658	205	436
Net income per common share (US\$/share)	5.11	1.53	3.23
Average exchange rate (US\$/C\$)	0.7135	0.6368	0.6457

Supplementary Information – FAS 69

(unaudited)

The supplemental data on the Company's oil and gas activities was prepared in accordance with the FASB's SFAS No. 69: Disclosures About Oil and Gas Producing Activities. Activities not directly associated with conventional crude oil and natural gas production, including synthetic oil operations, are excluded from all aspects of this supplementary oil and gas information.

Results of Operations from Oil and Gas Producing Activities

Years ended December 31 (millions of Canadian dollars)	North America	North Sea	Southeast Asia ¹	Sudan	Algeria	Trinidad	Other	Total
2003								
Net oil and gas revenue derived from proved reserves ²	2,070	1,754	400	112	43	—	—	4,379
Less: Production costs	367	583	87	18	16	—	—	1,071
Exploration and dry hole expense	222	90	26	5	1	34	86	464
Depreciation, depletion and amortization	647	635	95	—	17	—	—	1,394
Tax expense (recovery)	328	237	77	30	3	(12)	(31)	632
Results of operations	506	209	115	59	6	(22)	(55)	818
2002								
Net oil and gas revenue derived from proved reserves ²	1,634	1,914	356	500	—	—	—	4,404
Less: Production costs	339	588	86	84	—	—	—	1,097
Exploration and dry hole expense	194	29	23	19	5	46	43	359
Depreciation, depletion and amortization	583	701	87	92	—	—	—	1,463
Tax expense (recovery)	205	430	75	85	(2)	(22)	(18)	753
Results of operations	313	166	85	220	(3)	(24)	(25)	732
2001								
Net oil and gas revenue derived from proved reserves ²	1,744	1,584	350	389	—	—	—	4,067
Less: Production costs	323	467	70	66	—	—	—	926
Exploration and dry hole expense	123	51	16	27	7	15	21	260
Depreciation, depletion and amortization	549	558	93	77	—	—	—	1,277
Tax expense (recovery)	273	247	95	52	(3)	(6)	(9)	649
Results of operations	476	261	76	167	(4)	(9)	(12)	955

1 Includes operations in Indonesia and Malaysia/Vietnam.

2 Net oil and gas revenue derived from proved reserves is net of applicable royalties.

Capitalized Costs Related to Oil and Gas Activities

Years ended December 31 (millions of Canadian dollars)	North America	North Sea	Southeast Asia ¹	Sudan	Algeria	Trinidad	Other	Total
2003								
Proved properties	7,751	6,339	1,466	—	151	120	—	15,827
Unproved properties	227	88	95	—	67	16	3	496
Incomplete wells and facilities	31	1	22	—	—	1	5	60
	8,009	6,428	1,583	—	218	137	8	16,383
Less: accumulated depreciation, depletion and amortization	2,694	3,451	498	—	16	—	—	6,659
Net capitalized costs	5,315	2,977	1,085	—	202	137	8	9,724
2002								
Proved properties	6,939	5,592	1,422	986	217	45	—	15,201
Unproved properties	214	14	156	36	29	9	—	458
Incomplete wells and facilities	33	66	22	17	—	—	—	138
	7,186	5,672	1,600	1,039	246	54	—	15,797
Less: accumulated depreciation, depletion and amortization	2,339	2,774	509	271	—	—	—	5,893
Net capitalized costs	4,847	2,898	1,091	768	246	54	—	9,904
2001								
Proved properties	6,183	4,454	1,092	889	26	—	—	12,644
Unproved properties	408	284	195	30	94	17	—	1,028
Incomplete wells and facilities	24	37	56	22	23	6	—	168
	6,615	4,775	1,343	941	143	23	—	13,840
Less: accumulated depreciation, depletion and amortization	1,926	1,965	419	178	—	—	—	4,488
Net capitalized costs	4,689	2,810	924	763	143	23	—	9,352

1 Includes operations in Indonesia and Malaysia/Vietnam.

Costs Incurred in Oil and Gas Activities

Years ended December 31 (millions of Canadian dollars)			North America	North Sea	Southeast Asia ¹	Sudan	Algeria	Trinidad	Other	Total
2003	Property acquisition costs	Proved	369	189	—	—	—	—	—	558
		Unproved	184	2	—	—	—	—	3	189
	Exploration costs		336	99	70	7	4	58	90	664
	Development costs		600	397	246	(5)	30	72	—	1,340
	Asset retirement cost		115	285	7	—	—	—	—	407
	Total costs incurred		1,604	972	323	2	34	130	93	3,158
2002	Property acquisition costs	Proved	174	88	—	—	—	—	—	262
		Unproved	50	13	—	—	—	9	—	72
	Exploration costs		271	134	36	27	3	54	43	568
	Development costs		457	297	233	71	103	14	—	1,175
	Total costs incurred		952	532	269	98	106	77	43	2,077
2001	Property acquisition costs	Proved	828	213	129	—	—	—	—	1,170
		Unproved	240	19	245	—	—	—	—	504
	Exploration costs		251	106	31	42	22	31	21	504
	Development costs		527	527	110	75	41	—	—	1,280
	Total costs incurred		1,846	865	515	117	63	31	21	3,458

1 Includes operations in Indonesia and Malaysia/Vietnam.

Standardized Measure of Discounted Future Net Cash Flows from Proved Reserves

Future net cash flows were calculated by applying the respective year end prices to the Company's estimated future production of proved reserves and deducting estimates of future development and production costs and income taxes. Future development and production costs have been estimated based on existing economic and operating conditions. Future income taxes have been estimated based on statutory tax rates enacted at year end. The present values of the estimated future cash flows were determined by applying a 10% discount rate prescribed by the FASB.

In order to increase the comparability between companies, the standardized measure of discounted future net cash flows necessarily employs uniform assumptions that do not necessarily reflect management's best estimate of future events and anticipated outcomes. Accordingly, the Company does not believe that the standardized measure of discounted future net cash flows will be representative of actual future net cash flows and should not be considered to represent the fair market value of the oil and gas properties. Actual future net cash flows will differ significantly from those estimated due to, but not limited to, the following:

- production rates will differ from those estimated both in terms of timing and amount. For example, future production may include significant additional volumes from unproved reserves;
- future prices and economic conditions will differ from those at year end. For example, changes in prices decreased the discounted future net cash flows by \$3.2 billion in 2003;
- future production and development costs will be determined by future events and will differ from those at year end; and
- estimated income taxes will differ in terms of amounts and timing dependent on the above factors, changes in enacted rates and the impact of future expenditures on unproved properties.

The standardized measure of discounted future net cash flows was prepared using the following prices:

		2003	2002	2001
Crude oil and liquids (\$/bbl)	North America	33.32	42.07	22.48
	North Sea	37.89	46.84	29.61
	Southeast Asia ¹	41.71	49.22	30.10
	Sudan	—	44.09	23.89
	Algeria	38.91	48.37	29.20
	Trinidad	39.12	45.72	—
		37.04	45.13	26.34
Natural Gas (\$/mcf)	North America	6.32	6.06	3.49
	North Sea	5.55	5.59	4.97
	Southeast Asia ¹	3.74	4.94	2.54
	Trinidad	1.03	1.26	—
		5.17	5.43	3.25

1 Includes operations in Indonesia and Malaysia/Vietnam.

Discounted Future Net Cash Flows from Proved Reserves

As at December 31 (millions of Canadian dollars)		North America	North Sea	Southeast Asia ¹	Sudan	Algeria	Trinidad	Total
2003	Future cash inflows ²	18,444	11,032	5,930	—	645	928	36,979
	Future costs							
	Production	(4,958)	(5,686)	(1,107)	—	(165)	(122)	(12,038)
	Development and site restoration	(1,490)	(1,989)	(697)	—	(14)	(248)	(4,438)
	Future net inflows before income taxes	11,996	3,357	4,126	—	466	558	20,503
	Future income and production revenue taxes	(3,664)	(1,393)	(1,601)	—	(107)	(299)	(7,064)
	Future net cash flows	8,332	1,964	2,525	—	359	259	13,439
	10% discount factor	(3,740)	(147)	(1,118)	—	(86)	(112)	(5,203)
	Discounted future net cash flows	4,592	1,817	1,407	—	273	147	8,236
2002	Future cash inflows ²	19,639	13,160	6,627	4,090	675	1,143	45,334
	Future costs							
	Production	(4,325)	(5,577)	(1,040)	(999)	(230)	(157)	(12,328)
	Development and site restoration	(995)	(1,873)	(709)	(313)	(64)	(368)	(4,322)
	Future net inflows before income taxes	14,319	5,710	4,878	2,778	381	618	28,684
	Future income and production revenue taxes	(5,654)	(2,597)	(2,011)	(744)	(31)	(370)	(11,407)
	Future net cash flows	8,665	3,113	2,867	2,034	350	248	17,277
	10% discount factor	(3,913)	(554)	(1,387)	(655)	(97)	(161)	(6,767)
	Discounted future net cash flows	4,752	2,559	1,480	1,379	253	87	10,510
2001	Future cash inflows ²	11,376	9,347	4,026	2,924	493	—	28,166
	Future costs							
	Production	(3,449)	(4,253)	(875)	(991)	(155)	—	(9,723)
	Development and site restoration	(567)	(1,616)	(850)	(217)	(71)	—	(3,321)
	Future net inflows before income taxes	7,360	3,478	2,301	1,716	267	—	15,122
	Future income and production revenue taxes	(2,509)	(1,284)	(929)	(361)	(26)	—	(5,109)
	Future net cash flows	4,851	2,194	1,372	1,355	241	—	10,013
	10% discount factor	(1,797)	(292)	(804)	(478)	(121)	—	(3,492)
	Discounted future net cash flows	3,054	1,902	568	877	120	—	6,521

1 Includes operations in Indonesia and Malaysia/Vietnam.

2 Future cash inflows are revenues net of royalties.

Principal Sources of Changes in Discounted Cash Flows

Years ended December 31 (millions of Canadian dollars)	2003	2002	2001
Sales of oil and gas produced, net of production costs	(3,308)	(3,307)	(3,141)
Net change in prices	(3,200)	9,709	(11,795)
Net change in production costs	(357)	(1,990)	(692)
Net change in future development and site restoration costs	(87)	(637)	(128)
Development costs incurred during the year	672	764	375
Extensions, discoveries and improved recovery	1,229	1,863	1,542
Revisions of previous reserve estimates	92	37	216
Net purchases and sales of reserves in place	(1,225)	17	550
Accretion of discount	1,555	972	2,110
Net change in taxes	2,399	(3,342)	4,726
Other	(44)	(97)	166
Net change	(2,274)	3,989	(6,071)
Balance, beginning of year	10,510	6,521	12,592
Balance, end of year	8,236	10,510	6,521

Continuity of Proved Net Reserves¹

	North America ²	North Sea	Southeast Asia ³	Algeria	Sudan	Trinidad	Total
Crude Oil and Liquids (mmbbls)							
Total Proved							
Proved reserves at December 31, 2000	165.9	233.8	17.9	12.2	92.4	—	522.2
Discoveries, additions and extensions	17.9	53.9	15.3	7.1	22.5	—	116.7
Purchase of reserves	8.1	16.2	10.6	—	—	—	34.9
Sale of reserves	(2.9)	(4.8)	—	—	—	—	(7.7)
Net revisions and transfers	4.7	(0.5)	1.1	(2.4)	13.3	—	16.2
2001 Production	(17.9)	(38.4)	(5.3)	—	(11.9)	—	(73.5)
Proved reserves at December 31, 2001	175.8	260.2	39.6	16.9	116.3	—	608.8
Discoveries, additions and extensions	10.6	13.5	5.8	1.3	19.0	18.9	69.1
Purchase of reserves	1.1	7.5	—	—	—	—	8.6
Sale of reserves	(3.7)	(2.8)	—	—	—	—	(6.5)
Net revisions and transfers	(2.5)	13.9	(4.2)	(4.3)	(27.7)	—	(24.8)
2002 Production	(17.2)	(44.7)	(5.1)	—	(13.3)	—	(80.3)
Proved reserves at December 31, 2002	164.1	247.6	36.1	13.9	94.3	18.9	574.9
Discoveries, additions and extensions	13.1	8.3	17.0	2.3	—	—	40.7
Purchase of reserves	1.1	21.1	—	—	—	—	22.2
Sale of reserves	(4.6)	—	—	—	(91.7)	—	(96.3)
Net revisions and transfers	1.1	19.4	4.8	0.5	—	(0.8)	25.0
2003 Production	(16.4)	(41.4)	(5.4)	(0.1)	(2.6)	—	(65.9)
Proved reserves at December 31, 2003	158.4	255.0	52.5	16.6	—	18.1	500.6
Proved Developed							
December 31, 2000	160.9	173.3	15.2	—	77.4	—	426.8
December 31, 2001	168.6	203.8	13.3	—	89.6	—	475.3
December 31, 2002	157.2	210.8	11.9	2.4	84.1	—	466.4
December 31, 2003	155.4	211.8	18.6	14.6	—	—	400.4
Natural Gas (bcf)							
Total Proved							
Proved reserves at December 31, 2000	1,757.1	272.6	540.2	—	—	—	2,569.9
Discoveries, additions and extensions	293.8	13.7	455.2	—	—	—	762.7
Purchase of reserves	293.6	22.8	125.7	—	—	—	442.1
Sale of reserves	(44.7)	(1.5)	—	—	—	—	(46.2)
Net revisions and transfers	(24.9)	(5.0)	23.4	—	—	—	(6.5)
2001 Production	(222.3)	(35.3)	(32.4)	—	—	—	(290.0)
Proved reserves at December 31, 2001	2,052.6	267.3	1,112.1	—	—	—	3,432.0
Discoveries, additions and extensions	283.1	14.0	11.7	—	—	220.0	528.8
Purchase of reserves	31.5	0.4	—	—	—	—	31.9
Sale of reserves	(26.7)	—	—	—	—	—	(26.7)
Net revisions and transfers	(110.8)	(4.3)	(122.6)	—	—	—	(237.7)
2002 Production	(243.6)	(39.5)	(32.3)	—	—	—	(315.4)
Proved reserves at December 31, 2002	1,986.1	237.9	968.9	—	—	220.0	3,412.9
Discoveries, additions and extensions	276.3	1.0	64.0	—	—	—	341.3
Purchase of reserves	92.2	14.4	—	—	—	—	106.6
Sale of reserves	(11.4)	—	—	—	—	—	(11.4)
Net revisions and transfers	(14.9)	19.8	(6.1)	—	—	(9.0)	(10.2)
2003 Production	(247.6)	(37.5)	(40.1)	—	—	—	(325.2)
Proved reserves at December 31, 2003	2,080.7	235.6	986.7	—	—	211.0	3,514.0
Proved Developed							
December 31, 2000	1,568.4	215.9	120.0	—	—	—	1,904.3
December 31, 2001	1,804.7	213.8	252.0	—	—	—	2,270.5
December 31, 2002	1,746.9	210.0	471.6	—	—	—	2,428.5
December 31, 2003	1,890.4	200.7	593.9	—	—	—	2,685.0

1 Net reserves are after deducting royalties. See note 1(g) of the Consolidated Financial Statements for additional disclosure regarding royalties.

2 North American net proved reserves exclude synthetic crude oil reserves: 2001 — 36.4 mmbbls; 2002 — 36.7 mmbbls; 2003 — 35.8 mmbbls.

3 Includes operations in Indonesia and Malaysia/Vietnam.

Additional Information for US Readers

Note to US Readers

The US Securities and Exchange Commission (SEC) normally permits oil and gas companies to disclose in their filings with the SEC only proved reserves that have been demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. Accordingly, the probable reserves and the calculations with respect thereto included in this report do not meet the SEC's standards for inclusion in documents filed with the SEC.

Unless otherwise indicated, the financial statements and other Canadian financial information included in this Annual Report are presented in

accordance with Canadian generally accepted accounting principles that differ from generally accepted accounting principles in the US. See note 19 to the Consolidated Financial Statements for information concerning significant differences between Canadian and US generally accepted accounting principles.

The following information is for US readers. Production, recycle ratio, finding and development costs, finding, development and acquisition costs as well as netbacks have been calculated net of royalties and have been translated to US\$ at the average exchange rate for each of the years shown. (2003 US\$1=C\$1.40; 2002 US\$1=C\$1.57; 2001 US\$1=C\$1.55; 2000 US\$1=C\$1.49; 1999 US\$1=C\$1.49).

Net Production (after royalties)

	2003	2002	2001	2000	1999
Crude Oil and Liquids (bbls/d)					
North America	45,035	47,182	49,145	49,018	44,114
North Sea	113,291	122,231	105,138	107,554	58,039
Southeast Asia ¹	14,853	14,025	14,667	13,853	17,149
Algeria	3,351	—	—	—	—
Sudan	6,997	36,346	32,422	28,001	9,079
Total oil and liquids	183,527	219,784	201,372	198,426	128,381
Natural Gas (mmcf/d)					
North America	678	665	608	582	552
North Sea	103	107	97	117	111
Southeast Asia ¹	110	89	89	104	103
Total natural gas	891	861	794	803	766
Total conventional (mboe/d)	332	363	334	332	256
Synthetic Oil (Canada) (bbls/d)	2,510	2,788	2,387	1,927	2,556
Total (mboe/d)	334	366	337	335	259

¹ Includes operations in Indonesia and Malaysia/Vietnam.

Recycle Ratio¹

	1999	2000	2001	2002	2003	3-Year	5-Year
Netback (US\$/boe) — average annual	9.53	17.04	16.64	15.78	19.57	17.28	16.00
Finding and development	1.2	3.0	3.8	1.3	1.7	2.2	2.2
Finding, development and acquisition	1.3	3.3	2.8	1.3	1.6	2.0	2.1

¹ Average annual netback divided by finding, development and acquisition costs.

Finding, Development and Acquisition Costs (net after royalties)

	1999	2000	2001	2002	2003	3-year	5-year
Proved Reserves Additions (mmboe) ¹							
North America	32.4	74.8	67.5	36.9	57.6	162.0	269.2
International	49.2	52.9	191.5	55.9	63.0	310.4	412.6
Total	81.6	127.7	259.0	92.8	120.6	472.4	681.8
Proved Acquisitions (mmboe) ²							
North America	98.4	5.9	57.0	6.4	16.5	79.9	184.2
International	75.5	54.8	51.6	7.6	23.4	82.6	212.8
Total	173.9	60.7	108.6	14.0	39.9	162.5	397.1
Capital Spending (millions of US dollars) ³							
Exploration and development							
North America	195	410	502	464	668	1,634	2,239
International	425	321	638	631	745	2,014	2,760
Total Company	620	731	1,140	1,095	1,413	3,648	4,999
Acquisitions	1,292	254	1,080	212	533	1,825	3,371
Total Capital	1,912	985	2,220	1,307	1,946	5,473	8,370
Proved F&D Cost (US\$/boe) ⁴							
North America	6.01	5.48	7.44	12.56	11.60	10.09	8.32
International	8.63	6.07	3.33	11.29	11.82	6.49	6.69
Total	7.59	5.72	4.40	11.80	11.71	7.72	7.33
Proved FD&A Cost (US\$/boe) ⁵							
North America	7.91	6.13	9.57	14.02	14.34	11.83	9.68
International	7.02	4.55	4.23	11.04	10.22	6.65	6.36
Total	7.48	5.23	6.04	12.24	12.12	8.62	7.76

1 Proved discoveries and revisions for conventional oil only, excluding acquisitions.

2 Proved reserves purchased. Excludes dispositions.

3 Exploration and development spending excludes synthetic oil operations capital, Chauvin pipeline, Canadian midstream and capitalized interest.

4 F&D net costs/boe have been calculated by dividing finding and development costs (excluding acquisition costs) in US dollars by proved net after royalties reserves additions including revisions but excluding acquired proved net after royalties reserves.

5 FD&A net costs/boe have been calculated by dividing finding and development costs (including acquisition costs) in US dollars by proved net after royalties reserves additions including revisions and acquired proved net after royalties reserves. Dispositions are excluded from this calculation.

F&D and FD&A costs have been calculated in US dollars in a manner consistent with US practice. The calculation is based on current additions to proved reserves net after royalties.

Six mcf of natural gas equals one boe.

Reconciliation of Costs included in F&D Calculations (net after royalties)

US\$ millions	1999	2000	2001	2002	2003	3-Year	5-Year
Exploration and development costs (FAS 69)	648	742	1,152	1,111	1,430	3,693	5,083
Less: capitalized interest	(28)	(11)	(12)	(16)	(17)	(45)	(84)
Exploration and development costs	620	731	1,140	1,095	1,413	3,648	4,999
Acquisition costs (FAS 69)	1,292	254	1,080	212	533	1,825	3,371
Total exploration, development and acquisition costs	1,912	985	2,220	1,307	1,946	5,473	8,370

US Readers:
Product Netbacks

(Net of Royalties) — US\$

		2003	2002	2001
North America	Oil and Liquids (US\$/bbl)			
	Sales Price	25.20	20.65	19.89
	Hedging (gain)	2.21	0.04	(0.10)
	Operating costs	5.67	4.48	4.33
		17.32	16.13	15.66
	Natural Gas (US\$/mcf)			
	Sales Price	4.55	2.52	3.48
	Hedging (gain)	0.10	(0.22)	0.02
	Operating costs	0.68	0.56	0.57
		3.77	2.18	2.89
North Sea	Oil and Liquids (US\$/bbl)			
	Sales Price	28.35	24.68	23.29
	Hedging (gain)	1.43	0.08	(0.12)
	Operating costs	9.02	7.38	6.83
		17.90	17.22	16.58
	Natural Gas (US\$/mcf)			
	Sales Price	3.26	2.48	2.81
	Hedging (gain)	—	—	—
	Operating costs	0.41	0.44	0.33
		2.85	2.04	2.48
Southeast Asia¹	Oil and Liquids (US\$/bbl)			
	Sales Price	29.30	25.13	23.22
	Hedging (gain)	2.78	0.06	(0.28)
	Operating costs	8.60	8.09	6.53
		17.92	16.98	16.97
	Natural Gas (US\$/mcf)			
	Sales Price	3.53	3.01	3.10
	Hedging (gain)	—	—	0.01
	Operating costs	0.38	0.40	0.32
		3.15	2.61	2.77
Algeria	Oil (US\$/bbl)			
	Sales Price	27.84	—	—
	Hedging (gain)	3.13	—	—
	Operating costs	9.61	—	—
		15.10	—	—
Sudan	Oil (US\$/bbl)			
	Sales Price	31.33	24.06	21.09
	Hedging (gain)	—	0.08	(0.14)
	Operating costs	4.96	4.02	3.60
		26.37	19.96	17.63
Total Company	Oil and Liquids (US\$/bbl)			
	Sales Price	27.76	23.74	21.95
	Hedging (gain)	1.71	0.07	(0.13)
	Operating costs	8.02	6.25	5.64
		18.03	17.42	16.44
	Natural Gas (US\$/mcf)			
	Sales Price	4.27	2.57	3.37
	Hedging (gain)	0.07	(0.17)	0.01
	Operating costs	0.61	0.53	0.52
		3.59	2.21	2.84

¹ Includes operations in Indonesia and Malaysia/Vietnam.
Netbacks do not include synthetic oil or pipeline operations.

Historical Financial Summary

(millions of Canadian dollars unless otherwise stated)

Years ended December 31	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
Balance Sheets										
Current assets	975	917	799	1,042	730	272	471	362	256	426
Other assets	139	166	92	82	93	100	88	63	51	61
Goodwill	473	469	467	—	—	—	—	—	—	—
Property, plant and equipment	9,778	10,042	9,461	7,501	6,983	4,997	4,441	3,333	2,733	2,772
Total assets	11,365	11,594	10,819	8,625	7,806	5,369	5,000	3,758	3,040	3,259
Current liabilities	1,218	989	1,204	1,311	1,060	576	497	338	225	241
Deferred credits and other liabilities	2,985	3,106	2,695	1,997	968	587	601	426	280	235
Long-term debt	2,203	2,997	2,794	1,703	2,157	2,071	1,739	899	906	1,203
Shareholders' equity	4,959	4,502	4,126	3,614	3,621	2,135	2,163	2,095	1,629	1,580
Total liabilities and shareholders' equity	11,365	11,594	10,819	8,625	7,806	5,369	5,000	3,758	3,040	3,259
Income Statements										
Revenue										
Gross sales	5,295	5,299	5,047	4,836	2,318	1,534	1,700	1,407	1,011	720
Less royalties	894	927	989	946	389	214	312	224	144	130
Net sales	4,401	4,372	4,058	3,890	1,929	1,320	1,388	1,183	867	590
Other	76	80	82	99	46	51	42	30	32	23
Total revenue	4,477	4,452	4,140	3,989	1,975	1,371	1,430	1,213	899	613
Expenses										
Operating	1,099	1,115	946	827	604	581	480	300	245	166
General and administrative	152	138	108	95	70	59	57	56	57	41
Depreciation, depletion and amortization	1,443	1,495	1,313	1,153	747	615	541	421	369	212
Dry hole	251	174	113	77	51	91	42	65	26	33
Exploration	213	185	147	100	79	102	92	63	50	44
Interest on long-term debt	137	164	139	136	120	91	51	69	86	41
Stock based compensation	185	—	—	—	—	—	—	—	—	—
Other	16	113	78	64	(140)	199	(15)	(25)	(33)	(18)
Total expenses	3,496	3,384	2,844	2,452	1,531	1,738	1,248	949	800	519
Gain on sale of Sudan operations	296	—	—	—	—	—	—	—	—	—
Income (loss) before taxes	1,277	1,068	1,296	1,537	444	(367)	182	264	99	94
Taxes										
Current income tax	229	258	342	334	49	15	38	51	11	24
Future income tax (recovery)	(51)	162	72	196	109	(88)	60	84	50	31
Petroleum revenue tax	92	124	149	150	31	20	32	35	—	—
	270	544	563	680	189	(53)	130	170	61	55
Net income (loss)	1,007	524	733	857	255	(314)	52	94	38	39
Preferred security charges, net of tax	22	24	24	22	13	—	—	—	—	—
Income from discontinued operations	—	—	—	—	—	—	—	—	6	25
Net income (loss) available to common shareholders	985	500	709	835	242	(314)	52	94	44	64

Consolidated Financial Ratios

The following financial ratios are provided in connection with the Company's shelf prospectuses filed with Canadian and US securities regulatory authorities and are based on the Company's consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

The asset coverage ratios are calculated as at December 31, 2003. The interest coverage ratios are for the 12-month period then ended.

December 31, 2003	Preferred Securities as Equity ⁵	Preferred Securities as Debt ⁶
Interest coverage (times)		
Income ¹	8.21	6.65
Cash flow ²	19.22	15.59
Asset coverage (times)		
Before deduction of future income taxes and deferred credits ³	4.60	3.92
After deduction of future income taxes and deferred credits ⁴	3.25	2.76

1 Net income plus income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

2 Cash flow plus current income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

3 Total assets minus current liabilities; divided by long-term debt.

4 Total assets minus current liabilities and long-term liabilities excluding long-term debt; divided by long-term debt.

5 The Company's preferred securities are classified as equity and the related charges have been excluded from interest expense.

6 Reflect adjusted ratios had the preferred securities been treated as debt and the related charges been included in interest expense.

Ratios and Key Indicators

(millions of Canadian dollars unless otherwise stated)

Years ended December 31	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
Net income	1,007	524	733	857	255	(314)	52	94	38	39
Cash flow	2,729	2,645	2,494	2,413	1,111	631	797	697	502	362
Current tax expense	229	258	342	334	49	15	38	51	11	24
Capital expenditures	2,986	2,150	2,213	1,643	1,559	1,289	1,088	783	489	429
Proceeds on property dispositions	(100)	(72)	(162)	(99)	(197)	(222)	(71)	(58)	(100)	(230)
Net capital expenditures	2,886	2,078	2,051	1,544	1,362	1,067	1,017	725	389	199
Debt/debt+equity (%)	31%	40%	42%	32%	38%	49%	45%	30%	36%	43%
Debt/cash flow (times)	0.81	1.13	1.20	0.72	1.98	3.31	2.18	1.29	1.80	3.32
Per common share										
Net income (loss) (\$)	7.65	3.73	5.25	6.05	1.93	(2.80)	0.48	0.90	0.46	0.82
Cash flow (\$)	21.21	19.73	18.48	17.51	8.91	5.64	7.29	6.71	5.21	4.63
Production (boe)	1.13	1.21	1.13	1.09	0.91	0.88	0.80	0.73	0.70	0.63
Proved gross reserves (at year end) (boe)	10.6	11.3	11.1	8.7	7.9	7.5	6.8	5.6	5.0	4.9
Average royalty rate (%)	16%	18%	20%	18%	16%	14%	18%	16%	14%	18%
Unit operating costs (\$/boe)	7.15	6.48	5.79	5.19	5.14	5.61	5.24	3.78	3.42	3.11
Unit DD&A (\$/boe)	9.92	9.19	8.58	7.70	7.72	6.21	6.18	5.54	5.45	4.36
Return on capital employed (%) ¹	13.7%	7.2%	11.8%	15.4%	5.1%	(7.7%)	1.5%	3.4%	1.4%	2.1%
Return on active capital employed (%) ²	16.0%	8.6%	14.4%	18.2%	6.3%	(10.5%)	2.0%	4.2%	1.7%	2.5%
Return on equity (%) ³	21.3%	12.1%	18.9%	23.7%	8.9%	(14.6%)	2.4%	5.0%	2.4%	3.6%

1 Net income/(average shareholders equity+average debt).

2 Net income/(average shareholders equity+average debt – average non-depleted capital).

3 Net income/average shareholders equity.

For the above calculations, the Company's preferred securities have been classified as equity.

Product Netbacks

		2003					2002					2001
		Total	Three months ended				Total	Three months ended				Total
C\$ Gross		Year	Dec 31	Sep 30	Jun 30	Mar 31	Year	Dec 31	Sep 30	Jun 30	Mar 31	Year
North America	Oil and liquids (\$/bbl)											
	Sales price	35.30	31.88	33.43	32.92	42.74	32.43	34.57	35.57	32.76	26.82	30.80
	Hedging (gain)	2.45	2.07	2.05	1.26	4.38	0.06	0.36	0.52	0.11	(0.77)	(0.12)
	Royalties	7.37	6.86	6.81	6.50	9.27	6.85	7.42	7.74	6.35	5.90	6.88
	Operating costs	6.28	6.76	6.21	5.89	6.27	5.55	6.20	5.91	4.64	5.48	5.22
		19.20	16.19	18.36	19.27	22.82	19.97	20.59	21.40	21.66	16.21	18.82
	Natural gas (\$/mcf)											
	Sales price	6.37	5.11	5.92	6.41	8.03	3.96	5.21	3.26	4.08	3.29	5.39
	Hedging (gain)	0.11	(0.04)	0.03	0.12	0.32	(0.28)	(0.11)	(0.37)	(0.21)	(0.42)	0.02
	Royalties	1.37	1.08	1.18	1.54	1.69	0.75	1.04	0.55	0.73	0.67	1.34
	Operating costs	0.75	0.78	0.77	0.70	0.76	0.71	0.78	0.74	0.65	0.66	0.67
		4.14	3.29	3.94	4.05	5.26	2.78	3.50	2.34	2.91	2.38	3.36
North Sea	Oil and liquids (\$/bbl)											
	Sales price	39.72	38.81	38.66	35.29	46.14	38.76	41.77	41.89	37.71	33.87	36.07
	Hedging (gain)	2.01	2.07	1.98	0.14	3.74	0.12	0.38	0.75	0.11	(0.74)	(0.17)
	Royalties	(0.08)	0.60	(0.27)	(0.89)	0.09	1.60	1.72	1.68	1.41	1.60	1.85
	Operating costs	12.67	11.82	12.12	12.91	14.04	11.11	12.00	12.74	9.51	10.27	10.06
		25.12	24.32	24.83	23.13	28.27	25.93	27.67	26.72	26.68	22.74	24.33
	Natural gas (\$/mcf)											
	Sales price	4.57	4.86	4.08	4.16	4.93	3.89	4.51	3.13	3.05	5.04	4.35
	Hedging (gain)	—	—	—	—	—	—	—	—	—	—	—
	Royalties	0.28	0.63	0.09	0.04	0.25	0.48	0.27	0.46	0.41	0.79	0.46
	Operating costs	0.54	0.48	0.71	0.38	0.58	0.61	0.92	0.61	0.49	0.45	0.46
		3.75	3.75	3.28	3.74	4.10	2.80	3.32	2.06	2.15	3.80	3.43
Southeast Asia¹	Oil and liquids (\$/bbl)											
	Sales price	41.05	41.36	38.26	37.81	47.08	39.46	45.04	41.27	38.77	32.84	35.97
	Hedging (gain)	2.37	2.10	2.07	1.26	4.30	0.06	0.36	0.53	0.11	(0.76)	(0.30)
	Royalties	16.09	15.69	14.43	15.86	18.71	14.83	17.13	16.13	13.76	12.34	10.69
	Operating costs	7.33	6.83	7.13	7.22	8.37	7.93	8.67	8.30	7.61	7.15	7.13
		15.26	16.74	14.63	13.47	15.70	16.64	18.88	16.31	17.29	14.11	18.45
	Natural gas (\$/mcf)											
	Sales price	4.95	4.63	4.41	5.05	6.09	4.72	6.00	4.12	4.92	3.96	4.80
	Hedging (gain)	—	—	—	—	—	—	—	—	—	—	0.02
	Royalties	0.29	0.33	0.24	0.27	0.34	0.25	0.31	0.24	0.25	0.20	0.24
	Operating costs	0.50	0.41	0.53	0.49	0.64	0.59	0.80	0.69	0.49	0.42	0.47
		4.16	3.89	3.64	4.29	5.11	3.88	4.89	3.19	4.18	3.34	4.07
Algeria	Oil (\$/bbl)											
	Sales price	39.01	39.70	39.37	35.05	40.33	—	—	—	—	—	—
	Hedging (gain)	2.23	2.11	2.07	1.26	4.40	—	—	—	—	—	—
	Royalties	19.18	18.52	20.38	18.04	20.16	—	—	—	—	—	—
	Operating costs	6.84	4.30	12.24	4.07	6.23	—	—	—	—	—	—
		10.76	14.77	4.68	11.68	9.54	—	—	—	—	—	—
Sudan	Oil (\$/bbl)											
	Sales price	43.89	—	—	—	43.89	37.79	46.30	38.33	36.64	29.35	32.66
	Hedging (gain)	—	—	—	—	—	0.07	0.37	0.52	0.11	(0.75)	(0.13)
	Royalties	20.34	—	—	—	20.34	14.94	21.74	12.45	13.96	11.32	12.78
	Operating costs	3.73	—	—	—	3.73	3.82	3.72	4.07	4.55	2.89	3.40
		19.82	—	—	—	19.82	18.96	20.47	21.29	18.02	15.89	16.61
Total Company	Oil and liquids (\$/bbl)											
	Sales price	38.93	37.53	37.15	34.87	44.85	37.20	41.47	39.64	36.46	31.27	33.99
	Hedging (gain)	2.05	2.08	2.01	0.65	3.14	0.09	0.37	0.63	0.11	(0.75)	(0.16)
	Royalties	5.59	5.13	4.20	3.83	8.53	6.83	8.85	6.66	6.32	5.52	6.22
	Operating costs	9.63	9.51	9.89	9.87	9.36	7.99	8.53	8.89	7.17	7.38	7.15
		21.66	20.81	21.05	20.52	23.82	22.29	23.72	23.46	22.86	19.12	20.78
	Natural gas (\$/mcf)											
	Sales price	6.03	5.02	5.59	6.09	7.48	4.03	5.20	3.32	4.02	3.55	5.22
	Hedging (gain)	0.08	(0.03)	0.02	0.10	0.25	(0.22)	(0.09)	(0.30)	(0.16)	(0.33)	0.02
	Royalties	1.14	0.93	0.98	1.28	1.40	0.67	0.89	0.51	0.65	0.63	1.14
	Operating costs	0.70	0.70	0.74	0.65	0.72	0.69	0.80	0.72	0.62	0.61	0.63
		4.11	3.42	3.85	4.06	5.11	2.89	3.60	2.39	2.91	2.64	3.43

¹ Includes operations in Indonesia and Malaysia/Vietnam.
Netbacks do not include synthetic oil or pipeline operations.

Historical Operations Summary

Years ended December 31	2003	2002	2001	2000	1999	1998	1997	1996	1995	1994
Daily Average Production										
Crude oil (bbls/d)										
North America	44,456	46,287	50,424	51,005	44,806	45,103	40,627	34,169	31,019	29,801
North Sea	110,613	124,965	108,163	109,096	57,267	54,988	48,065	30,675	16,987	7,114
Southeast Asia ¹	23,159	21,925	20,326	19,627	28,286	31,684	28,458	22,621	18,121	5,919
Algeria	6,594	—	—	—	—	—	—	—	—	—
Sudan	13,039	60,109	53,257	45,869	11,726	—	—	—	—	—
Other	—	—	—	—	—	—	—	—	—	473
Natural gas liquids (bbls/d)										
North America	12,473	13,521	12,851	12,829	10,918	9,818	8,054	7,598	7,097	5,512
North Sea	2,462	2,521	2,665	2,806	1,989	2,492	2,437	2,363	1,791	538
Southeast Asia ¹	1,271	544	547	579	566	—	—	—	—	—
Synthetic oil (Canada) (bbls/d)	2,649	2,868	2,781	2,540	2,765	2,664	2,536	2,534	2,527	2,425
Total oil and liquids	216,716	272,740	251,014	244,351	158,323	146,749	130,177	99,960	77,542	51,782
Natural gas (mmcf/d)										
North America	864	820	809	755	681	631	558	557	581	481
North Sea	109	122	108	122	115	104	100	90	69	15
Southeast Asia ¹	117	94	93	111	108	13	—	—	—	—
Total natural gas	1,090	1,036	1,010	988	904	748	658	647	650	496
Total (mboe/d)	398	445	419	409	309	271	240	208	186	134
WTI (average US\$/bbl)	30.99	26.15	25.92	30.26	19.30	14.37	20.61	22.02	18.40	17.19
NYMEX gas (average US\$/mmbtu)	5.44	3.25	4.38	4.30	2.27	2.08	2.48	2.67	1.71	1.91
\$C/\$US exchange rate (year end)	0.7738	0.6331	0.6279	0.6666	0.6887	0.6511	0.6987	0.7298	0.7331	0.7129

¹ Includes operations in Indonesia and Malaysia/Vietnam.

Reserves

Continuity of Proved Gross Reserves

	North America ¹	North Sea	Southeast Asia ²	Algeria	Sudan	Trinidad	Total
Crude Oil and Liquids (mmbbls)							
Total Proved							
Proved reserves at December 31, 2000	199.3	246.0	25.5	20.3	140.7	—	631.8
Discoveries, additions and extensions	21.3	54.9	22.6	14.9	30.2	—	143.9
Purchase of reserves	10.7	20.4	14.7	—	—	—	45.8
Sale of reserves	(3.9)	(5.2)	—	—	—	—	(9.1)
Net revisions and transfers	8.0	(1.1)	4.1	—	4.8	—	15.8
2001 Production	(23.1)	(40.5)	(7.6)	—	(19.4)	—	(90.6)
Proved reserves at December 31, 2001	212.3	274.5	59.3	35.2	156.3	—	737.6
Discoveries, additions and extensions	13.0	13.5	9.6	2.6	32.3	19.2	90.2
Purchase of reserves	1.4	7.5	—	—	—	—	8.9
Sale of reserves	(4.6)	(2.8)	—	—	—	—	(7.4)
Net revisions and transfers	(1.2)	3.5	—	(10.4)	(5.8)	—	(13.9)
2002 Production	(21.8)	(46.5)	(8.3)	—	(21.9)	—	(98.5)
Proved reserves at December 31, 2002	199.1	249.7	60.6	27.4	160.9	19.2	716.9
Discoveries, additions and extensions	16.0	8.2	25.2	3.9	—	—	53.3
Purchase of reserves	1.3	21.1	—	—	—	—	22.4
Sale of reserves	(5.3)	—	—	—	(156.1)	—	(161.4)
Net revisions and transfers	(0.1)	18.7	7.6	0.1	—	—	26.3
2003 Production	(20.8)	(41.3)	(9.0)	(2.4)	(4.8)	—	(78.3)
Proved reserves at December 31, 2003	190.2	256.4	84.4	29.0	—	19.2	579.2
Proved Developed							
December 31, 2000	192.7	182.4	21.6	—	117.9	—	514.6
December 31, 2001	203.0	215.7	20.4	—	120.4	—	559.5
December 31, 2002	190.0	212.6	19.7	4.8	143.4	—	570.5
December 31, 2003	186.4	213.0	29.5	25.5	—	—	454.4
Natural Gas (bcf)							
Total Proved							
Proved reserves at December 31, 2000	2,216.8	286.0	769.5	—	—	—	3,272.3
Discoveries, additions and extensions	374.1	14.2	657.5	—	—	—	1,045.8
Purchase of reserves	365.0	57.1	173.9	—	—	—	596.0
Sale of reserves	(57.0)	(1.6)	—	—	—	—	(58.6)
Net revisions and transfers	(6.6)	(14.0)	30.6	—	—	—	10.0
2001 Production	(295.5)	(39.5)	(34.0)	—	—	—	(369.0)
Proved reserves at December 31, 2001	2,596.8	302.2	1,597.5	—	—	—	4,496.5
Discoveries, additions and extensions	374.2	15.4	19.7	—	—	223.5	632.8
Purchase of reserves	37.7	0.4	—	—	—	—	38.1
Sale of reserves	(34.9)	—	—	—	—	—	(34.9)
Net revisions and transfers	(80.3)	(11.3)	(54.4)	—	—	—	(146.0)
2002 Production	(300.1)	(44.6)	(34.5)	—	—	—	(379.2)
Proved reserves at December 31, 2002	2,593.4	262.1	1,528.3	—	—	223.5	4,607.3
Discoveries, additions and extensions	351.5	1.0	107.0	—	—	—	459.5
Purchase of reserves	107.1	14.4	—	—	—	—	121.5
Sale of reserves	(14.3)	—	—	—	—	—	(14.3)
Net revisions and transfers	(77.0)	17.5	(20.6)	—	—	—	(80.1)
2003 Production	(315.8)	(39.9)	(42.7)	—	—	—	(398.4)
Proved reserves at December 31, 2003	2,644.9	255.1	1,572.0	—	—	223.5	4,695.5
Proved Developed							
December 31, 2000	1,972.3	227.0	170.9	—	—	—	2,370.2
December 31, 2001	2,281.8	247.4	358.5	—	—	—	2,887.7
December 31, 2002	2,278.7	232.8	723.8	—	—	—	3,235.3
December 31, 2003	2,404.0	220.1	920.9	—	—	—	3,545.0

¹ North American gross proved reserves exclude synthetic crude oil reserves: 2001 – 43.4 mmbbls; 2002 – 43.2 mmbbls; 2003 – 42.3 mmbbls.

² Includes operations in Indonesia and Malaysia/Vietnam.

Historical Proved Reserves¹

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Crude Oil and Liquids (mmbbls)										
Opening balance	95.0	167.8	167.9	225.9	300.3	416.5	557.1	631.8	737.6	716.9
Discoveries, additions and extensions	8.8	15.4	33.8	68.7	83.3	62.0	72.5	143.9	90.2	53.3
Dispositions and acquisitions	69.9	0.9	35.6	29.0	67.3	111.3	57.2	36.7	1.5	(139.0)
Net revisions and transfers	12.2	11.2	24.3	23.2	18.2	24.1	33.5	15.8	(13.9)	26.3
Production	(18.1)	(27.4)	(35.7)	(46.5)	(52.6)	(56.8)	(88.5)	(90.6)	(98.5)	(78.3)
Closing balance	167.8	167.9	225.9	300.3	416.5	557.1	631.8	737.6	716.9	579.2
Natural Gas (bcf)										
Opening balance	1,267.9	1,852.1	1,901.8	2,301.7	2,663.5	2,834.4	3,221.0	3,272.3	4,496.5	4,607.3
Discoveries, additions and extensions	186.0	195.3	263.9	407.6	396.0	301.0	472.3	1,045.8	632.8	459.5
Dispositions and acquisitions	564.1	9.5	34.2	289.6	(51.7)	368.6	(53.9)	537.4	3.2	107.2
Net revisions and transfers	15.1	82.0	338.7	(95.2)	100.2	47.4	(5.0)	10.0	(146.0)	(80.1)
Production	(181.0)	(237.1)	(236.9)	(240.2)	(273.6)	(330.4)	(362.1)	(369.0)	(379.2)	(398.4)
Closing balance	1,852.1	1,901.8	2,301.7	2,663.5	2,834.4	3,221.0	3,272.3	4,496.5	4,607.3	4,695.5
BOE² (mmboe)										
Opening balance	306.3	476.5	485.0	609.5	744.2	888.8	1,094.0	1,177.2	1,487.0	1,484.7
Discoveries, additions and extensions	39.8	47.9	77.7	136.6	149.2	112.0	151.1	318.2	195.7	129.8
Dispositions and acquisitions	163.9	2.5	41.3	77.3	58.7	172.8	48.1	126.2	2.1	(121.1)
Net revisions and transfers	14.8	25.0	80.7	7.4	34.9	32.2	32.8	17.5	(38.4)	13.2
Production	(48.3)	(66.9)	(75.2)	(86.6)	(98.2)	(111.8)	(148.8)	(152.1)	(161.7)	(144.7)
Closing balance	476.5	485.0	609.5	744.2	888.8	1,094.0	1,177.2	1,487.0	1,484.7	1,361.9

1 Gross reserves, excluding sulphur and synthetic oil.

2 Six mcf of natural gas equals one boe.

Over the past two years, Talisman has played a leading role in the Alberta Securities Commission process to develop new disclosure standards for reserves. The Company supports the objective of fostering investor confidence in reserves and has advocated uniformity with its North American peer group. In response to the recommendations, Talisman undertook a thorough review of its procedures for evaluating and booking reserves. The Company also established a Board committee to review the reserves process and disclosure and has established the position of an internal qualified reserves evaluator (IQRE). The IQRE provides a report to the Reserves Committee and a regulatory certificate regarding proved reserves and their related cash flows.

Talisman continues to do a complete internal evaluation of proved reserves annually, supported by external audits. Over the past three years, 90% of the Company's reserves have been independently audited. As a result of these reviews, the Company is confident that its reserves booking procedures and internal controls accurately capture and report its reserves. The empirical evidence for this is the Company's continued production growth, low and positive level of historical reserve revisions and low percentage of proved undeveloped reserves (PUD) in North America.

Talisman replaced 150% of production from all sources in 2003 (including proved and probable discoveries, revisions and net acquisitions excluding Sudan). On the basis of proved reserves, the Company replaced 127% of production from all sources and 102% through drilling, excluding Sudan.

Year end proved reserves were 1,362 mmboe, a 3% increase over 2002, excluding Sudan, largely due to increases in Malaysia/Vietnam and the US. Proved reserves per share increased by 5%, excluding Sudan. Overall revisions and transfers were positive, adding 13 mmboe. Probable reserves increased 4% to 873 mmboe, excluding Sudan.

Proved natural gas reserves increased 2% to 4,696 bcf. Approximately 57% of Talisman's proved reserves are natural gas, of which 56% (2,645 bcf) are situated in North America. Proved oil reserves increased by 4%, excluding Sudan, to 579 mmbbls. Virtually all of these reserves are high quality, medium-light crude oil and natural gas liquids.

PUDs account for only 7% of Talisman's North American total proved reserves. While international PUDs are higher at 37%, these are reserves with a high degree of certainty in well defined projects. Talisman's North Sea PUDs are in projects under development and for which near term development drilling is scheduled. Southeast Asia PUDs relate to the South Angsi development oil and gas reserves (under contract) in the PM-3 CAA in Malaysia and in the Corridor Block in Indonesia. These are long life gas contracts backstopped by proved reserves. Trinidad PUDs are associated with the Greater Angostura development, which is currently under construction.

At year end 2003 (based on 2003 production excluding Sudan), Talisman had a reserve life index of 9.7 years for proved reserves and 16 years based on proved plus probable reserves.

Probable Reserves¹

	North America	North Sea	Southeast Asia ²	Algeria	Sudan	Trinidad	Total
Crude Oil and Liquids (mmbbls)							
Probable reserves at December 31, 2002	86.3	141.9	56.7	40.4	52.3	19.3	396.9
Discoveries, additions and extensions	0.1	17.0	7.1	(3.9)	—	—	20.3
Dispositions and acquisitions	(1.3)	17.0	—	—	(52.3)	—	(36.6)
Net revisions and transfers	1.7	(3.6)	(0.5)	3.7	—	—	1.3
Probable reserves at December 31, 2003	86.8	172.3	63.3	40.2	—	19.3	381.9
Natural Gas (bcf)							
Probable reserves at December 31, 2002	1,398.3	101.3	1,388.5	—	—	92.0	2,980.1
Discoveries, additions and extensions	86.9	12.3	(13.7)	—	—	39.9	125.4
Dispositions and acquisitions	(2.2)	16.0	—	—	—	—	13.8
Net revisions and transfers	(123.4)	5.0	(54.6)	—	—	—	(173.0)
Probable Reserves at December 31, 2003	1,359.6	134.6	1,320.2	—	—	131.9	2,946.3
BOE³ (mmboe)							
Probable reserves at December 31, 2002	319.3	158.7	288.1	40.4	52.3	34.6	893.4
Discoveries, additions and extensions	14.6	19.0	4.8	(3.9)	—	6.7	41.2
Dispositions and acquisitions	(1.6)	19.7	—	—	(52.3)	—	(34.2)
Net revisions and transfers	(18.9)	(2.7)	(9.5)	3.7	—	—	(27.4)
Probable reserves at December 31, 2003	313.4	194.7	283.4	40.2	—	41.3	873.0

¹ Gross probable reserves, excluding sulphur and synthetic oil.

² Includes operations in Indonesia and Malaysia/Vietnam.

³ Six mcf of natural gas equals one boe.

Finding and Development Costs

Talisman's finding and development (F&D) costs averaged \$14.28/boe (US\$11.71/boe net) in 2003.

Based on 2003 drilling results, Talisman's North American F&D costs averaged \$13.72/boe. Approximately half of the increase over 2002 can be attributed to higher spending on land, geological and geophysical expenses (G&G) and, to a lesser extent, plant and equipment. Land and G&G represent an investment in potential future reserve additions. Timing was also an issue in 2003, where money spent in some areas (e.g. Appalachia and Monkman) will result in reserves additions in 2004.

Talisman also drilled more wells in 2003 to capitalize on higher gas prices and although this resulted in lower reserve adds per well, the investments were highly profitable at prevailing prices.

Including net revisions, North American F&D costs were \$16.62/boe in 2003. Revisions and transfers in 2003 had the net effect of lowering

North American proved reserves by 13 mmboe (less than 1% of Company total). The main reason for the revision was a detailed internal review of properties acquired by Talisman several years ago. For these reasons, the Company believes that three-year F&D costs are a better reflection of underlying performance.

International F&D costs were \$12.52/boe in 2003, although again Talisman believes the three-year average of \$7.03/boe is more representative. At year end, Talisman had over 100 mmboe of probable reserves (in Corridor gas in Indonesia and the J1/J5 oil discoveries in the North Sea), which will be transferred to proved, pending gas sales contracts and final project approvals in 2004. Had these reserves been booked in 2003, Talisman's international F&D costs would have been \$5.62/boe.

Finding, development and acquisition (FD&A) costs were \$14.67/boe in 2003 and largely reflect Talisman's asset acquisitions in Appalachia and Norway. Sudan has been excluded from the FD&A calculations because the sale of such a large property distorts the results so much that meaningful comparisons are not possible.

Finding, Development and Acquisition Costs (gross before royalties)

	1999	2000	2001	2002	2003	3-year	5-year
Proved Reserves Additions (mmboe) ¹							
North America	55.1	93.2	90.6	60.7	61.6	212.9	361.2
International	89.1	90.7	245.1	96.6	81.5	423.2	603.0
Total	144.2	183.9	335.7	157.3	143.1	636.1	964.2
Proved Net Acquisitions (mmboe) ²							
North America	95.2	(6.0)	58.1	(2.7)	11.5	66.9	156.1
International	77.6	54.1	68.1	4.8	23.5	96.4	228.1
Total	172.8	48.1	126.2	2.1	35.0	163.3	384.2
Capital Spending (millions of dollars) ³							
Exploration and development							
North America	300.5	658.7	821.2	753.9	1,023.6	2,598.7	3,557.9
International	621.1	459.6	971.1	980.7	1,019.7	2,971.5	4,052.2
Total Company	921.6	1,118.3	1,792.3	1,734.6	2,043.3	5,570.2	7,610.1
Net acquisitions and divestitures	1,581.5	209.5	1,478.1	203.4	568.4	2,249.9	4,040.9
Total Capital	2,503.1	1,327.8	3,270.4	1,938.0	2,611.7	7,820.1	11,651.0
Proved F&D Cost (\$/boe) ⁴							
North America	5.45	7.07	9.06	12.42	16.62	12.20	9.85
International	6.97	5.06	3.96	10.15	12.52	7.03	6.72
Total	6.39	6.08	5.34	11.03	14.28	8.76	7.89
Proved FD&A Cost (\$/boe) ⁵							
North America	8.35	7.39	11.75	15.00	19.09	14.34	11.43
International	7.49	4.72	4.86	10.53	11.59	7.33	6.91
Total	7.90	5.72	7.08	12.15	14.67	9.79	8.64

1 Proved discoveries and revisions only, excluding acquisitions, conventional oil only.

2 Reserve purchases less dispositions, includes asset sales, dispositions, swaps and corporate acquisitions. Excludes the impacts of the sale of the Sudan operations in 2003.

3 Exploration and development spending excludes indirect exploration expenses, synthetic oil operations capital, enhanced oil recovery, Chauvin pipeline, Canadian midstream and capitalized interest.

4 F&D costs have been calculated by dividing finding and development (excluding net acquisition costs) in Canadian dollars by proved gross before royalties reserves additions including revisions but excluding net acquired proved gross after royalty reserves.

5 FD&A costs have been calculated by dividing finding and development costs (including net acquisition costs) in Canadian dollars by proved gross before royalties reserves additions including revisions and net acquired proved gross before royalty reserves.

No amount of future capital has been included in the FD&A calculation, which is consistent with calculations performed in prior years.

Six mcf of natural gas equals one boe.

Recycle Ratio¹

	1999	2000	2001	2002	2003	3-Year	5-Year
Netback (\$/boe) – average annual	11.87	20.73	20.70	20.34	23.00	21.30	19.71
Finding and development	1.9	3.4	3.9	1.8	1.6	2.4	2.5
Finding, development and acquisition	1.5	3.6	2.9	1.7	1.6	2.2	2.3

1 Average annual netback divided by finding, development and acquisition costs.

Reconciliation of Costs included in F&D Calculations (gross before royalties)

(C\$ millions)	1999	2000	2001	2002	2003	3-Year	5-Year
Exploration and development expenditures	996	1,179	1,882	1,848	2,180	5,910	8,085
Less:							
Midstream capital	—	(1)	(27)	(21)	(27)	(75)	(76)
Indirect costs	(23)	(33)	(34)	(41)	(52)	(127)	(183)
Capitalized interest	(41)	(16)	(19)	(25)	(24)	(68)	(125)
Synthetic oil operations capital	(9)	(8)	(8)	(24)	(30)	(62)	(79)
Enhanced recovery expenditures	(1)	(3)	(2)	(2)	(4)	(8)	(12)
	922	1,118	1,792	1,735	2,043	5,570	7,610

Detailed Property Reviews

2003 Landholdings

(thousands of acres)	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Canada						
Western Canada	2,844	1,493	5,128	3,443	7,972	4,936
Ontario	366	238	836	588	1,202	826
Other ¹	—	—	3,930	331	3,930	331
United States	11	11	1,038	884	1,049	895
Total North America	3,221	1,742	10,932	5,246	14,153	6,988
North Sea	412	140	2,117	1,036	2,529	1,176
Southeast Asia						
Indonesia	293	127	2,798	817	3,091	944
Malaysia and Vietnam	224	93	3,582	1,238	3,806	1,331
Papua New Guinea	—	—	187	90	187	90
Total Southeast Asia	517	220	6,567	2,145	7,084	2,365
Algeria	77	5	751	263	828	268
Trinidad	—	—	323	136	323	136
Other²	—	—	2,422	1,578	2,422	1,578
Total International	1,006	365	12,180	5,158	13,186	5,523
Total Worldwide	4,227	2,107	23,112	10,404	27,339	12,511
Synthetic Oil	9	1	410	39	419	40

1 Includes Yukon Territory, Northwest Territories, Arctic Islands and Scotia Slope.

2 Includes Colombia, Qatar and Falkland Islands.

2003 Drilling

Year Ended December 31, 2003		Exploration				Development				Total			
		Oil	Gas	Dry	Total	Oil	Gas	Dry	Total	Oil	Gas	Dry	Total
North America													
Canada	Gross	14	147.0	22.0	183.0	190.0	225.0	21.0	436.0	204.0	372.0	43.0	619.0
	Net	9.4	100.9	15.9	126.2	101.0	132.7	18.2	251.9	110.4	233.6	34.1	378.1
United States	Gross	—	6.0	—	6.0	—	—	—	—	—	6.0	—	6.0
	Net	—	4.2	—	4.2	—	—	—	—	—	4.2	—	4.2
North Sea	Gross	3.0	—	2.0	5.0	12.0	2.0	3.0	17.0	15.0	2.0	5.0	22.0
	Net	2.2	—	1.1	3.3	5.5	0.2	0.9	6.6	7.7	0.2	2.0	9.9
Southeast Asia													
Indonesia	Gross	—	1.0	2.0	3.0	6.0	—	—	6.0	6.0	1.0	2.0	9.0
	Net	—	0.4	0.5	0.9	2.6	—	—	2.6	2.6	0.4	0.5	3.5
Malaysia and Vietnam	Gross	2.0	4.0	1.0	7.0	12.0	9.0	—	21.0	14.0	13.0	1.0	28.0
	Net	0.9	1.6	0.4	2.9	4.9	3.6	—	8.5	5.8	5.2	0.4	11.4
Algeria	Gross	1.0	—	—	1.0	11.0	—	—	11.0	12.0	—	—	12.0
	Net	0.4	—	—	0.4	0.6	—	—	0.6	1.0	—	—	1.0
Sudan	Gross	2.0	—	—	2.0	1.0	—	—	1.0	3.0	—	—	3.0
	Net	0.5	—	—	0.5	0.3	—	—	0.3	0.8	—	—	0.8
Trinidad	Gross	1.0	2.0	—	3.0	—	—	—	—	1.0	2.0	—	3.0
	Net	0.4	0.6	—	1.0	—	—	—	—	0.4	0.6	—	1.0
Total	Gross	23.0	160.0	27.0	210.0	232.0	236.0	24.0	492.0	255.0	396.0	51.0	702.0
	Net	13.8	107.7	17.9	139.4	114.9	136.5	19.1	270.5	128.7	244.2	37.0	409.9

Water injection, source and disposal wells are not included.

Five Year Drilling Results

	2003	2002	2001	2000	1999		2003	2002	2001	2000	1999
North America						International					
Total oil wells	204	146	258	282	88	Total oil wells	51	59	131	96	89
Total gas wells	378	223	241	256	178	Total gas wells	18	11	7	7	8
Drilling success (%)	93	87	90	88	90	Drilling success (%)	90	77	83	87	87

Property Review:
North America¹

Property		Average WI (%)	2003	2002²	2001²
Greater Arch					
Production:	Oil & Liquids (bbls/d)	82	7,734	8,842	10,347
	Natural Gas (mmcf/d)	75	152.4	166.9	204.2
Drilling:	Total Production (boe/d)		33,131	36,654	44,379
	Number of wells		72	79	96
	Success Rate (%)		75	71	76
Capital Expenditures:	(C\$ million)		119	114	136
Alberta Foothills					
Production:	Oil & Liquids (bbls/d)		169	167	139
	Natural Gas (mmcf/d)	86	129.9	121.1	102.4
Drilling:	Total Production (boe/d)		21,812	20,353	17,210
	Number of wells		32	22	21
	Success Rate (%)		94	95	100
Capital Expenditures:	(C\$ million)		163	118	142
Chauvin					
Production:	Oil & Liquids (bbls/d)	97	15,334	14,265	12,578
	Natural Gas (mmcf/d)		17.2	18.3	16.7
Drilling:	Total Production (boe/d)		18,195	17,312	15,361
	Number of wells		79	60	90
	Success Rate (%)		99	93	99
Capital Expenditures:	(C\$ million)		53	48	76
Northern Plains					
Production:	Oil & Liquids (bbls/d)	88	1,456	1,642	2,810
	Natural Gas (mmcf/d)	65	30.8	33.0	43.1
Drilling:	Total Production (boe/d)		6,595	7,142	9,988
	Number of wells		5	6	8
	Success Rate (%)		63	50	75
Capital Expenditures:	(C\$ million)		29	25	18
Ontario					
Production:	Oil & Liquids (bbls/d)	98	2,257	2,664	3,056
	Natural Gas (mmcf/d)	91	17.9	20.2	18.9
Drilling:	Total Production (boe/d)		5,242	6,034	6,198
	Number of wells		20	29	35
	Success Rate (%)		70	79	94
Capital Expenditures:	(C\$ million)		20	41	43
Monkman-BC Foothills					
Production:	Oil & Liquids (bbls/d)		—	—	11
	Natural Gas (mmcf/d)	68	86.6	82.7	90.0
Drilling:	Total Production (boe/d)		14,430	13,770	15,016
	Number of wells		5	2	5
	Success Rate (%)		100	100	80
Capital Expenditures:	(C\$ million)		51	44	17
Carlyle					
Production:	Oil & Liquids (bbls/d)	85	7,199	7,657	9,421
	Natural Gas (mmcf/d)		1.0	1.0	0.9
Drilling:	Total Production (boe/d)		7,369	7,824	9,576
	Number of wells		15	13	17
	Success Rate (%)		93	100	89
Capital Expenditures:	(C\$ million)		14	13	15
Edson Area (includes West Whitecourt, Bigstone/Wild River)					
Production:	Oil & Liquids (bbls/d)	89	4,022	4,189	3,449
	Natural Gas (mmcf/d)	85	197.8	199.7	162.7
Drilling:	Total Production (boe/d)		36,995	37,465	30,565
	Number of wells		130	79	95
	Success Rate (%)		96	96	85
Capital Expenditures:	(C\$ million)		281	192	169

Property Review:
North America¹ (continued)

Property		Average WI (%)	2003	2002 ²	2001 ²
Lac La Biche					
Production:	Natural Gas (mmcf/d)	84	49.2	56.3	63.9
	Total Production (boe/d)		8,208	9,383	10,647
Drilling:	Number of wells		24	12	17
	Success Rate (%)		83	83	100
Capital Expenditures:	(C\$ million)		12	6	19
Central Alberta (includes Acme)					
Production:	Oil & Liquids (bbls/d)	92	2,112	2,632	2,981
	Natural Gas (mmcf/d)	78	17.4	19.2	22.2
	Total Production (boe/d)		5,015	5,832	6,676
Drilling:	Number of wells		8	6	11
	Success Rate (%)		100	100	100
Capital Expenditures:	(C\$ million)		16	18	35
Southern Alberta Foothills					
Production:	Oil & Liquids (bbls/d)	83	2,422	2,264	2,105
	Natural Gas (mmcf/d)	94	10.9	10.3	6.8
	Total Production (boe/d)		4,242	3,978	3,231
Drilling:	Number of wells		17	4	5
	Success Rate (%)		100	100	100
Capital Expenditures:	(C\$ million)		67	22	23
Shaunavon					
Production:	Oil & Liquids (bbls/d)	84	3,624	3,724	3,813
Drilling:	Number of wells		34	7	4
	Success Rate (%)		100	86	100
Capital Expenditures:	(C\$ million)		17	4	6
Other					
Production:	Oil & Liquids (bbls/d)		8,865	10,198	11,384
	Natural Gas (mmcf/d)		41.8	53.1	58.7
	Total Production (boe/d)		15,819	19,050	21,048
Drilling:	Number of wells		115	65	115
	Success Rate (%)		99	87	60
Capital Expenditures:	(C\$ million)		118	130	133
Syncrude					
	Synthetic oil (bbls/d)	1.25	2,649	2,868	2,781
Deep Basin					
Production:	Oil & Liquids (bbls/d)		1,735	1,564	1,181
	Natural Gas (mmcf/d)	83	50.9	38.2	18.5
	Total Production (boe/d)		10,212	7,937	4,264
Drilling:	Number of wells		60	40	37
	Success Rate (%)		97	100	97
Capital Expenditures:	(C\$ million)		91	47	44
United States:					
Appalachia					
Production:	Natural Gas (mmcf/d)	100	59.9	—	—
	Total Production (boe/d)		9,984	—	—
Drilling:	Number of wells		6	—	—
	Success Rate (%)		100	—	—
Capital Expenditures:	(C\$ million)		58	—	—
Total Production:					
	Oil & Liquids (bbls/d)		59,578	62,676	66,056
	Natural Gas (mmcf/d)		863.7	820.0	809.0
	(boe/d)		203,522	199,326	200,753
Total Capital Expenditures:					
	(C\$ million)		1,109	822	876

1 All production volumes are shown before royalties.

2 Prior year drilling statistics have been revised as necessary, such that all reported numbers are stated within the definitions used for 2003.

Property Review:

North Sea¹

Property	Average WI (%)	2003	2002 ²	2001 ²
Mid-North Sea				
Clyde/Orion/Halley	13-95			
Production:	Oil & Liquids (bbls/d)	13,014	14,688	15,112
	Natural Gas (mmcf/d)	4.4	4.5	7.1
	Total Production (boe/d)	13,742	15,446	16,297
Drilling:	Number of wells	2	2	2
Capital Expenditures:	(C\$ million)	132	94	77
Buchan/Hannay				
Production:	Oil & Liquids (bbls/d)	8,526	8,062	5,990
	Natural Gas (mmcf/d)	0.4	0.7	1.0
	Total Production (boe/d)	8,598	8,178	6,165
Drilling:	Number of wells	2	4	3
Capital Expenditures:	(C\$ million)	55	89	89
Ross/Blake				
Production:	Oil & Liquids (bbls/d)	22,437	27,017	16,029
	Natural Gas (mmcf/d)	7.0	7.7	3.0
	Total Production (boe/d)	23,601	28,294	16,524
Drilling:	Number of wells	3	—	4
Capital Expenditures:	(C\$ million)	125	4	163
Beatrice				
Production:	Oil & Liquids (bbls/d)	5,603	7,406	2,160
Drilling:	Number of wells	—	1	3
Capital Expenditures:	(C\$ million)	4	16	104
Flotta Catchment Area				
Production:	Oil & Liquids (bbls/d)			
	Tartan/Highlander/Petronella	6,706	10,008	9,447
	Piper	11,862	16,009	19,070
	MacCulloch	6,045	6,184	4,761
	Claymore	18,692	20,045	17,496
	Natural Gas (mmcf/d)			
	MacCulloch and Piper	0.7	1.4	0.9
	Total Production (boe/d)	43,414	52,488	50,926
Drilling:	Number of wells	6	8	5
Capital Expenditures:	(C\$ million)	121	186	145
Norway (Gyda)				
Production:	Oil & Liquids (bbls/d)	2,574	—	—
	Natural Gas (mmcf/d)	1.3	—	—
	Total Production (boe/d)	2,788	—	—
Drilling:	Number of wells	—	—	—
Capital Expenditures:	(C\$ million)	12	—	—
Non-Operated				
Brae				
Production:	Oil & Liquids (bbls/d)	7,883	8,801	9,221
	Natural Gas (mmcf/d)	83.6	93.2	79.3
	Total Production (boe/d)	21,816	24,330	22,440
Drilling:	Number of wells	2	1	4
Capital Expenditures:	(C\$ million)	15	4	11
Netherlands				
Production:	Oil & Liquids (bbls/d)	132	199	176
	Natural Gas (mmcf/d)	9.8	12.4	13.8
	Total Production (boe/d)	1,764	2,269	2,482
Drilling:	Number of wells	2	2	3
Capital Expenditures:	(C\$ million)	4	13	6

Property Review:

North Sea¹ (continued)

Property	Average WI (%)	2003	2002 ²	2001 ²
Other	2-60			
Production:	Oil & Liquids (bbls/d)	9,601	9,067	11,366
	Natural Gas (mmcf/d)	1.9	2.3	3.0
	Total Production	9,932	9,436	11,848
Drilling:	Number of wells	5	5	9
Capital Expenditures:	(C\$ million)	28	25	38
Total Production:	Oil & Liquids (bbls/d)	113,075	127,486	110,828
	Natural Gas (mmcf/d)	109.1	122.2	108.1
	(boe/d)	131,258	147,847	128,842
Total Capital Expenditures:	(C\$ million)	496	431	633

1 All production volumes are shown before royalties.

2 Prior year drilling statistics have been revised as necessary, such that all reported numbers are stated within the definitions used for 2003.

Southeast Asia¹

Property	Average WI (%)	2003	2002 ²	2001 ²
Corridor				
Production:	Oil & Liquids (bbls/d)			
	Corridor Technical Assistance Contract	40	4,329	5,344
	Corridor Production Sharing Contract	36	2,031	2,081
	Natural Gas (mmcf/d)			
	Corridor Production Sharing Contract	36	89.4	93.3
	Total Production (boe/d)	23,453	21,254	22,971
Drilling:	Number of wells	1	1	41
Capital Expenditures:	(C\$ million)	20	59	65
Tanjung Raya	100			
Production:	Oil & Liquids (bbls/d)	6,338	6,617	6,414
Drilling:	Number of wells		2	3
Capital Expenditures:	(C\$ million)	7	8	8
Ogan Komering	50			
Production:	Oil & Liquids (bbls/d)	2,443	2,721	3,340
	Natural Gas (mmcf/d)	6.8	5.0	—
	Total Production (boe/d)	3,590	3,563	3,340
Drilling:	Number of wells	2	6	12
Capital Expenditures:	(C\$ million)	4	3	7
Jambi	40			
Production:	Oil & Liquids (bbls/d)	1,066	1,154	1,420
Drilling:	Number of wells	4	—	9
Capital Expenditures:	(C\$ million)	2	0.5	3
Malaysia/Vietnam	41			
Production:	Oil & Liquids (bbls/d)	8,672	5,617	2,273
	Natural Gas (mmcf/d)	5.0	—	—
	Total Production (boe/d)	9,502	5,617	2,273
Drilling:	Number of wells	28	6	3
Capital Expenditures:	(C\$ million)	275	161	56
Other	25-60			
Drilling:	Number of wells	2	2	—
Capital Expenditures:	(C\$ million)	8	37.5	2
Total Production:	Oil & Liquids (bbls/d)	24,430	22,469	20,872
	Natural Gas (mmcf/d)	117.1	94.4	93.3
	(boe/d)	43,949	38,205	36,419
Total Capital Expenditures:	(C\$ million)	316	269	141

1 All production volumes are shown before royalties.

2 Prior year drilling statistics have been revised as necessary, such that all reported numbers are stated within the definitions used for 2003.

Property Review:

Algeria¹

	Average WI (%)	2003	2002 ²	2001 ²
Production:	Oil & Liquids (bbls/d)	35	6,594	
Drilling:	Number of wells	12	8	14
Capital Expenditures:	(C\$ million)	34	107	62

Sudan¹

Production:	Oil & Liquids (bbls/d)	25	13,039	60,109	53,257
Drilling:	Number of wells		3	30	44
Capital Expenditures:	(C\$ million)		2	98	117

Exploration Areas

Trinidad		25-65			
Drilling:	Number of wells		3	5	3
Capital Expenditures:	(C\$ million)		130	78	31
Colombia		30-70			
Drilling:	Number of wells		—	—	—
Capital Expenditures:	(C\$ million)		21	22	7
Other					
Drilling:	Number of wells		—	—	—
Capital Expenditures:	(C\$ million)		72	21	15

¹ All production volumes are shown before royalties.

² Prior year drilling statistics have been revised as necessary, such that all reported numbers are stated within the definitions used for 2003.

Investor Information

Common Shares

Transfer agent: Computershare Trust Company of Canada
Calgary, Toronto, Montreal, Vancouver

Co-transfer agent: Computershare Investor Services, LLC

Authorized: Unlimited number of common shares and unlimited number of first and second preferred shares

Issued: 127,998,728 common shares at December 31, 2003

Preferred Securities

Trustee: JP Morgan Chase Bank, New York

Issued: TLM PrB 6,000,000 8.9% Preferred Securities each having principal amount of US\$25

Stock Exchange Listings

Common Shares

Symbol: **TLM**

Canada: The Toronto Stock Exchange

United States: New York Stock Exchange

Preferred Securities

Symbol: **TLM PrB**

United States: New York Stock Exchange

Public Debt

Trustee: Computershare Trust Company of Canada

7.125% (US\$) unsecured debentures

9.80% unsecured debentures, Series B

7.25% (US\$) unsecured debentures

8.06% unsecured medium term notes

5.80% unsecured medium term notes

Trustee: JP Morgan Chase, London

6.625% (£) unsecured notes

Talisman's commercial paper is currently rated as:
Moody's — P-2

Talisman's public long-term debt is currently rated as:
Dominion Bond Rating Service — BBB (high);
Moody's — Baa1; S&P — BBB+

Private Debt

6.71% (US\$) unsecured notes, Series A

6.96% (US\$) unsecured notes

6.89% (US\$) unsecured notes, Series B

6.68% (US\$) unsecured notes

Dividends

In June 2003, the Company paid a semi-annual dividend of \$0.30 per share on Talisman's common shares. In December 2003, the Company paid a semi-annual dividend of \$0.40 per share on Talisman's common shares.

Market Information

Common Shares		2003		2002		2001	
		TSX (C\$)	NYSE (US\$)	TSX (C\$)	NYSE (US\$)	TSX (C\$)	NYSE (US\$)
Share Price (dollars)	High	73.80	56.98	70.09	45.70	65.77	42.30
	Low	55.12	35.30	51.30	32.10	46.51	29.76
	Close	73.52	56.60	56.85	36.17	60.50	37.85
Shares Traded (millions)	First quarter	38.3	10.1	26.4	7.9	42.2	7.9
	Second quarter	26.2	8.3	28	8.6	44.5	9.4
	Third quarter	23.8	7.9	29.7	10.8	35.3	8.5
	Fourth quarter	26.6	8.6	51.3	15.4	39.2	10.8
	Year	114.9	34.9	135.4	42.7	161.2	36.7
Year end shares outstanding (millions)		128		131		134	
Weighted average shares outstanding (millions)		129		134		135	
Year end stock options outstanding (millions)		7.9		7.4		7.5	

Executive Office

Talisman Energy Inc.

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Website

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E-mail: tim@talisman-energy.com

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Scotland
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Facsimile: (1224) 353-400

Talisman (Asia) Limited

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Jakarta, 12920, Indonesia
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Facsimile: (021) 521-0660

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Horseheads, New York 14845-8594
United States
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Facsimile: (607) 795-1041
www.fortunaenergy.com

Talisman Malaysia Limited

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Telephone: (603) 2162 6970
Facsimile: (603) 2162 6972

Talisman Energy Norge AS

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Facsimile: (47) 5200-1500

Talisman (Trinidad) Petroleum Ltd.

9th Floor, Albion Plaza Energy Centre
22-24 Victoria Avenue
Port of Spain
Trinidad, West Indies
Telephone: (868) 625-1515
Facsimile: (868) 624-7999

Talisman Energy (Qatar) Inc.

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Al Jaber Tower
Museum Street
Doha, Qatar
Telephone: (974) 435-1815
Facsimile: (974) 435-0980

Investor Relations Contacts

M. Jacqueline Sheppard

Executive Vice-President,
Corporate and Legal,
and Corporate Secretary
(403) 237-1183

David W. Mann

Senior Manager, Corporate and
Investor Communications
(403) 237-1196

Christopher LeGallais

Manager, Investor Relations
(403) 237-1957

Annual Meeting

The annual meeting of shareholders of Talisman Energy Inc. will be held at 10:30 a.m. on Tuesday, May 4, 2004 in the Exhibition Hall, North Building of the Telus Convention Center, 136 Eighth Avenue S.E., Calgary, Alberta. Shareholders are encouraged to attend the meeting, but those who are unable to do so are requested to participate by voting, using one of the three available methods: (i) by telephone, (ii) by internet, or (iii) by signing and returning the form of proxy or voting instruction form mailed with this report.

Directors and Executive

Board of Directors

Douglas D. Baldwin^{2,3,4,6}

Calgary, Alberta

Chairman, Talisman Energy Inc.

James W. Buckee²

Calgary, Alberta

President and Chief Executive Officer

Talisman Energy Inc.

Kevin S. Dunne^{3,5,6}

London, England

Corporate Director

Al L. Flood, C.M.^{1,4}

Thornhill, Ontario

Corporate Director

Dale G. Parker^{1,5}

Vancouver, British Columbia

Public Administration and Financial

Institution Advisor

Roland Priddle^{3,5}

Victoria, British Columbia

Consultant

Lawrence G. Tapp^{3,4}

Langley, British Columbia

Principal, Tapp Technologies

Stella M. Thompson^{4,5}

Calgary, Alberta

Principal, Governance West Inc.

President, Stellar Energy Ltd.

Robert G. Welty^{1,2}

Calgary, Alberta

Director and Chief Executive Officer,

Sterling Resources Ltd.

Charles W. Wilson^{1,2,6}

Evergreen, Colorado

Corporate Director

1 Member of Audit Committee

2 Member of Executive Committee

3 Member of Governance and
Nominating Committee

4 Member of Management Succession
and Compensation Committee

5 Member of Pension Funds Committee

6 Member of Reserves Committee

Executive

James W. Buckee

President and Chief Executive Officer

Ronald J. Eckhardt

Executive Vice-President, North American
Operations

T. Nigel D. Hares

Executive Vice-President, Frontier
and International Operations

Joseph E. Horler

Executive Vice-President, Marketing

Michael D. McDonald

Executive Vice-President, Finance and Chief
Financial Officer

Robert M. Redgate

Executive Vice-President, Corporate Services

M. Jacqueline Sheppard

Executive Vice-President, Corporate and Legal,
and Corporate Secretary

John 't Hart

Executive Vice-President, Exploration

Advisory — Forward-Looking Statements

This Annual Report contains statements that constitute forward-looking statements within the meaning of the United States Private Securities Litigation Reform Act of 1995.

Identifying Forward-Looking Statements

Forward-looking statements are included throughout this Annual Report, including among other places, under the headings “President’s Message”, “Business Environment”, “Objectives and Performance”, “2004 Outlook” and “Management’s Discussion and Analysis”. These statements include, among others, statements regarding:

- anticipated cash flow and cash flow per share;
- estimates of future sales, production and operations or financial performance;
- business plans for drilling, exploration and development;
- the estimated amounts and timing of capital expenditures;
- estimates of operating costs;
- business strategy and plans or budgets,
- outlook for oil and gas prices,
- anticipated liquidity, capital resources and debt levels;
- royalty rates and exchange rates;
- the merits or anticipated outcome of pending litigation; and
- other expectations, beliefs, plans, goals, objectives, assumptions, information and statements about possible future events, conditions, results of operations or performance.

Statements concerning oil and gas reserves contained in this Annual Report may be deemed to be forward-looking statements as they involve the implied assessment that the resources described can be profitably produced in the future, based on certain estimates and assumptions.

Often, but not always, forward-looking statements use words or phrases such as: “expects”, “does not expect” or “is expected”, “anticipates” or “does not anticipate”, “plans” or “planned”, “estimates” or “estimated”, “projects” or “projected”, “forecasts” or “forecasted”, “believes”, “intends”, “likely”, “possible”, “probable”, “scheduled” or “positioned”, or state that certain actions, events or results “may”, “could”, “would”, “might” or “will” be taken, occur or be achieved.

Material factors that could cause actual results to differ materially from those in forward-looking statements

Forward-looking statements are based on current expectations, estimates and projections that involve a number of risks and uncertainties, which could cause actual results to differ materially from those anticipated by Talisman Energy Inc. and described in the forward-looking statements. These risks and uncertainties include:

- the risks of the oil and gas industry, such as operational risks in exploring for, developing and producing crude oil and natural gas, and market demand;
- risks and uncertainties involving geology of oil and gas deposits;
- the uncertainty of reserves estimates and reserves life;
- the uncertainty of estimates and projections relating to production, costs and expenses;
- potential delays or changes in plans with respect to exploration or development projects or capital expenditures;
- fluctuations in oil and gas prices, foreign currency exchange rates and interest rates;
- health, safety and environmental risks;
- uncertainties as to the availability and cost of financing;
- uncertainties related to the litigation process, such as possible discovery of new evidence or acceptance of novel legal theories and the difficulties in predicting the decisions of judges and juries;
- risks in conducting foreign operations (for example, political and fiscal instability or the possibility of civil unrest or military action);
- general economic conditions;
- the effect of acts of, or actions against international terrorism; and
- the possibility that government policies or laws may change or governmental approvals may be delayed or withheld.

We caution that the foregoing list of risks and uncertainties is not exhaustive. Additional information on these and other factors which could affect the Company’s operations or financial results are included under the headings “Management’s Discussion and Analysis — Risks and Uncertainties” and “— Outlook for 2004” and elsewhere in this Annual Report. Additional information may also be found in the Company’s other reports on file with Canadian securities regulatory authorities and the United States Securities and Exchange Commission.

No obligation to update forward-looking statements

Forward-looking statements are based on the estimates and opinions of the Company’s management at the time the statements are made. The Company assumes no obligation to update forward-looking statements should circumstances or management’s estimates or opinions change.

Advisory – Reserves Data and Other Oil and Gas Information

Talisman's disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to Talisman by Canadian securities regulatory authorities, which permits Talisman to provide disclosure in accordance with US disclosure requirements. The information provided by Talisman may differ from the corresponding information prepared in accordance with Canadian disclosure standards under National Instrument 51-101 (NI 51-101). The proved reserves disclosed in this annual report have been calculated using the standards contained in Regulation S-X of the US Securities and Exchange Commission (SEC). The probable reserves disclosed in this annual report have been calculated using the definition for probable reserves set out by the Society of Petroleum Engineers/World Petroleum Congress. Further information on the differences between the US requirements and the NI 51-101 requirements is set forth under the heading "Note Regarding Reserves Data and Other Oil and Gas Information" in Talisman's Annual Information Form.

The exemption granted to Talisman also permits it to disclose internally evaluated reserves data. While Talisman annually obtains an independent audit of a portion of its reserves, no independent qualified reserves evaluator or auditor was involved in the preparation of the reserves data disclosed in this Annual Report.

Throughout this Annual Report, the calculation of barrels of oil equivalent (BOE) is calculated at a conversion rate of six thousand cubic feet (mcf) of natural gas for one barrel of oil and is based on an energy equivalence conversion method. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf:1 bbl is based on an energy equivalence conversion method primarily applicable at the burner tip and does not represent a value equivalence at the wellhead.

The finding, development and acquisition cost per BOE is calculated by dividing total capital expended on finding, development and acquisition activities by additions to proved reserves.

Advisory – Non-GAAP Financial Measures

Included in this Annual Report are references to financial measures commonly used in the oil and gas industry such as cash flow and cash flow per share. These financial measures have no standardized meaning and are not defined by Generally Accepted Accounting Principles in either Canada or the US. Consequently these are referred to as non-GAAP measures. Cash flow, as commonly used, appears as a separate caption on the Company's cash flow statement and is reconciled to both net income and cash flow from operations. Cash

flow is used by the Company to assess operating results between years and between peer companies with different accounting policies. Our reported amounts may not be comparable to similarly titled measures reported by other companies. Cash flow should not be considered an alternative to, or more meaningful than, cash provided by operating, investing and financing activities or net income as determined in accordance with Canadian GAAP as an indicator of the Company's performance or liquidity.

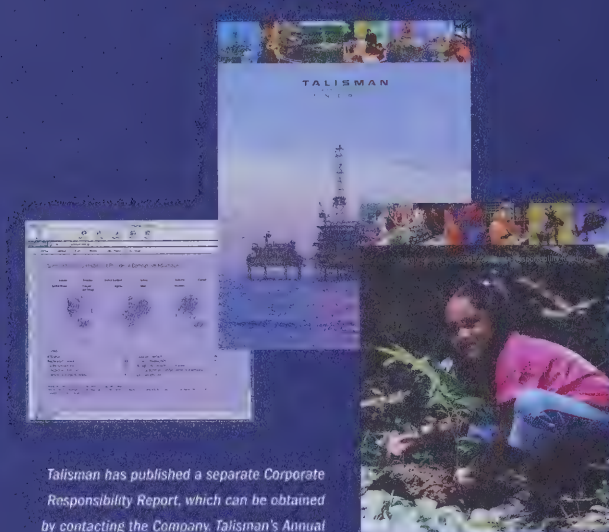
Abbreviations

API	American Petroleum Institute
bbls	barrels
bbls/d	barrels per day
bcf	billion cubic feet
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
C\$	Canadian dollars
FPSO	Floating, Production, Storage and Offloading Vessel
FSO	Floating, Storage and Offloading Vessel
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbbls	million barrels
mmboe	million barrels of oil equivalent
mmbtu	million British thermal units
mmcf	million cubic feet
Moody's	Moody's Investor Service

NYMEX	New York Mercantile Exchange
OECD	Organization of Economic Cooperation and Development
OPEC	Organization of Petroleum Exporting Countries
S&P	Standard & Poor's Ratings Group
tcf	trillion cubic feet
UK	United Kingdom
US	United States of America
US\$	United States dollars
WTI	West Texas Intermediate
£	pound sterling

Conversion & Equivalency Factors

Imperial		Metric
1 ton	=	0.907 tonnes
1 acre	=	0.40 hectares
1 barrel	=	0.159 cubic metres
1 cubic foot	=	0.0282 cubic metres



Talisman has published a separate Corporate Responsibility Report, which can be obtained by contacting the Company. Talisman's Annual and Corporate Responsibility reports can also be viewed on our website.

TALISMAN

E N E R G Y

Talisman Energy Inc.

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TALISMAN

ENERGY

OUR MISSION:
VALUE CREATION
IN THE GLOBAL
UPSTREAM OIL
AND GAS BUSINESS



ANNUAL INFORMATION FORM
MARCH 3, 2004

TALISMAN

E N E R G Y

**ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2003**

March 3, 2004

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FORWARD LOOKING STATEMENTS

This Annual Information Form contains or incorporates by reference statements that constitute “forward-looking statements” within the meaning of the United States (“U.S.”) *Private Securities Litigation Reform Act of 1995*.

Identifying forward-looking statements

Forward-looking statements are included throughout this Annual Information Form including, among other places, under the headings “General Development of the Business” and “Description of the Business” and in the “Management’s Discussion and Analysis”, incorporated herein by reference. These statements include, among others, statements regarding:

- business strategy and plans or budgets,
- outlook for oil and gas prices,
- estimates of future sales, production and operations or financial performance,
- business plans for drilling, exploration and development,
- the estimated amounts and timing of capital expenditures,
- estimates of operating costs,
- anticipated future debt levels,
- royalty rates and exchange rates,
- the merits or anticipated outcome of pending litigation, and
- other expectations, beliefs, plans, goals, objectives, assumptions, information and statements about possible future events, conditions, results of operations or performance.

Statements concerning oil and gas reserves contained in this Annual Information Form under the headings “Description of the Business – Reserves Estimates” and elsewhere may be deemed to be forward-looking statements as they involve the implied assessment that the resources described can be profitably produced in the future, based on certain estimates and assumptions.

Often, but not always, forward-looking statements use words or phrases such as: “expects”, “does not expect” or “is expected”, “anticipates” or “does not anticipate”, “plans” or “planned”, “estimates” or “estimated”, “projects” or “projected”, “forecasts” or “forecasted”, “believes”, “intends”, “likely”, “possible”, “probable”, “scheduled” or “positioned”, or state that certain actions, events or results “may”, “could”, “would”, “might” or “will” be taken, occur or be achieved.

Material factors that could cause actual results to differ materially from those in forward-looking statements

Forward-looking statements are based on current expectations, estimates and projections that involve a number of risks and uncertainties, which could cause actual results to differ materially from those anticipated by Talisman Energy Inc. (“Talisman” or the “Company”) and described in the forward-looking statements. These risks and uncertainties include:

- the risks of the oil and gas industry, such as operational risks in exploring for, developing and producing crude oil and natural gas and market demand;
- risks and uncertainties involving geology of oil and gas deposits;
- the uncertainty of reserves estimates and reserves life;
- the uncertainty of estimates and projections relating to production, costs and expenses;
- potential delays or changes in plans with respect to exploration or development projects or capital expenditures;
- fluctuations in oil and gas prices, foreign currency exchange rates and interest rates;
- health, safety and environmental risks;
- uncertainties as to the availability and cost of financing;
- uncertainties related to the litigation process, such as possible discovery of new evidence or acceptance of novel legal theories and the difficulties in predicting the decisions of judges and juries;
- risks in conducting foreign operations (for example, political and fiscal instability or the possibility of civil unrest or military action);
- general economic conditions;
- the effect of acts of, or actions against international terrorism; and
- the possibility that government policies or laws may change or governmental approvals may be delayed or withheld.

We caution that the foregoing list of risks and uncertainties is not exhaustive. Additional information on these and other factors which could affect the Company's operations or financial results are included under the headings "Risks and Uncertainties" and "Sensitivities" in the Management's Discussion and Analysis, in the Report on Reserves Data by Talisman's Internal Qualified Reserves Evaluator and the Report of Management and Directors on Oil and Gas Disclosure, attached as schedules to this Annual Information Form and elsewhere in this Annual Information Form. Additional information may also be found in the Company's other reports on file with Canadian securities regulatory authorities and the United States Securities and Exchange Commission (the "SEC").

No obligation to update forward-looking statements

Forward-looking statements are based on the estimates and opinions of the Company's management at the time the statements are made. The Company assumes no obligation to update forward-looking statements should circumstances or management's estimates or opinions change.

NOTE REGARDING RESERVES DATA AND OTHER OIL AND GAS INFORMATION

In 2003, the securities regulatory authorities in Canada (other than Quebec) adopted National Instrument 51-101 ("NI 51-101"), which imposes new oil and gas disclosure standards for Canadian public companies engaged in oil and gas activities. NI 51-101 and its companion policy specifically contemplate the granting of exemptions from some of the disclosure standards prescribed by NI 51-101 to companies that are active in the United States capital markets to permit the substitution of the disclosures required by the SEC rules in order to provide for comparability of oil and gas disclosure with that provided by U.S. and other international issuers. Talisman has obtained an exemption from Canadian securities regulatory authorities to permit it to provide disclosure in accordance with the relevant U.S. requirements. Accordingly, most of the reserves data and other oil and gas information included or incorporated by reference in this Annual Information Form is disclosed in accordance with U.S. disclosure requirements. Such information, as well as the information that Talisman discloses in the future in reliance on the exemption, may differ from the corresponding information prepared in accordance with NI 51-101 standards.

The primary differences between the U.S. requirements and the NI 51-101 requirements are that (i) SEC rules require disclosure only of proved reserves, whereas NI 51-101 requires disclosure of proved and probable reserves, and (ii) SEC rules require that the reserves and future net revenue be estimated under existing economic and operating conditions, whereas NI 51-101 requires disclosure of proved reserves and the associated future net revenue on a constant basis, and of proved, probable and proved plus probable reserves and the associated future net revenue on a forecast basis. The definitions of proved reserves differ, but Talisman does not believe that the differences in the definitions would result in any material difference in its reserves estimates for that category. The Canadian Oil and Gas Evaluation Handbook (the reference source for the definition of proved reserves under NI 51-101) states that the differences in the estimated proved reserves quantities based on constant prices should not be material.

Talisman has disclosed proved reserves (including continuity of reserves) using the standards contained in U.S. Regulation S-X and the standardized measure of discounted future net cash flows from proved reserves determined in accordance with Statement No. 69 of the U.S. Financial Accounting Standards Board. In addition, notwithstanding that Talisman is not required to disclose probable reserves, it has done so using the definition for probable reserves set out by the Society of Petroleum Engineers/World Petroleum Congress ("SPE/WPC"). Talisman does not believe that the differences in the SPE/WPC and NI 51-101 definitions of probable reserves would result in any material difference in its estimates of probable reserves disclosed in this Annual Information Form.

EXCHANGE RATE INFORMATION

Except where otherwise indicated, in this Annual Information Form all dollar amounts are stated in Canadian dollars. The following table sets forth the U.S./Canada exchange rates on the last day of the years indicated. The high, low and average exchange rates for each year were identified or calculated from spot rates in effect on each trading day during the relevant year. The exchange rates shown are expressed as the number of U.S. dollars required to purchase one Canadian dollar. These exchange rates are based on those published on the Bank of Canada's website as being in effect at approximately noon on each trading day (the "Bank of Canada noon rate").

Year ended December 31	2001	2002	2003
Year end	0.6279	0.6331	0.7738
High	0.6695	0.6618	0.7738
Low	0.6242	0.6199	0.6350
Average	0.6460	0.6369	0.7156

DEFINITIONS

The abbreviations set forth below have the following meanings:

bbls	barrels
bbls/d	barrels per day
mbbls	thousand barrels
mmbbls	million barrels
mcf	thousand cubic feet
mmcf/d	million cubic feet per day
boe	barrels of oil equivalent
liquids or NGLs	natural gas liquids

Natural gas is converted to oil equivalent at the ratio of 6 mcf to 1 boe. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6:1 is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Gross acres means the total number of acres in which Talisman has an interest. These figures include lands in respect of which the Company has royalty interests and net carried interests. Net acres means the number of acres obtained by multiplying the gross acres in each property by Talisman's percentage working interest. Net acres do not include lands in respect of which the Company has royalty interests and net carried interests.

Gross production means Talisman's working interest in production volumes before the deduction of royalties. Net production means Talisman's working interest in production volumes after deduction of royalties.

Gross wells means the total number of wells in which the Company has a working interest. Net wells means the aggregate of the percentage working interest of each of the gross wells.

CORPORATE STRUCTURE

Talisman is amalgamated under the *Canada Business Corporations Act*. The Company's registered and principal office is located at Suite 3400, 888 Third Street S.W., Calgary, Alberta T2P 5C5.

The following table sets forth the material operating subsidiaries owned directly or indirectly by Talisman, their jurisdictions of incorporation and the percentage of voting securities beneficially owned by Talisman as at December 31, 2003.

Name	Jurisdiction of Incorporation	Percentage of Voting Securities Owned ¹
Talisman Energy (UK) Limited	England	100%
Talisman North Sea Limited	England	100%
Talisman (Corridor) Ltd.	Barbados	100%
Petromet Resources Limited	Ontario, Canada	100%
Fortuna Energy Inc.	Delaware, U.S.	100%
Talisman Malaysia Limited	Barbados	100%

Note:

1 With the exception of Talisman Energy (UK) Limited and Talisman (Corridor) Ltd., none of the above subsidiaries has any non-voting securities outstanding. All of the non-voting securities of Talisman Energy (UK) Limited and Talisman (Corridor) Ltd. are directly or indirectly held by Talisman.

Unless the context indicates otherwise, a reference in this Annual Information Form to "Talisman" or the "Company" includes direct or indirect subsidiaries of Talisman Energy Inc. and partnership interests held by Talisman Energy Inc. and its subsidiaries.

Effective June 1, 2001, Talisman Energy Inc. and Petromet Resources Limited ("Petromet"), an indirect subsidiary of Talisman, formed an Alberta general partnership named Talisman Energy Canada (the "Partnership"). Talisman is the managing partner of the Partnership. Talisman and Petromet contributed to the Partnership substantially all of their oil and gas assets located in Canada, including their interests in the facilities for processing, treating, storing and transporting the production from such assets. Since that date, substantially all of Talisman's and Petromet's Canadian oil and gas operations have been carried on through the Partnership.

The above table does not include all of the subsidiaries of Talisman. The assets and revenues of unnamed operating subsidiaries, in the aggregate, did not exceed 20% of the total consolidated assets or total consolidated operating revenues, respectively, of Talisman as at, and for the year ended, December 31, 2003.

GENERAL DEVELOPMENT OF THE BUSINESS

Talisman is an independent, Canadian based, international upstream oil and gas company whose main business activities include exploration, development, production and marketing of crude oil, natural gas and natural gas liquids. The Company's reporting segments are North America, the North Sea, Southeast Asia and Algeria, where there are ongoing production, development and exploration activities. Sudan is also a reporting segment for Talisman, although the Company sold its indirectly held interest in Sudan in 2003. The Company is active in a number of other international areas, including Trinidad, Colombia and Qatar.

During the past three years, Talisman has developed its business and diversified its interests through a combination of exploration, development, acquisitions and dispositions.

In May 2001, Talisman, through a direct wholly owned subsidiary, acquired the outstanding shares of Petromet. The Petromet assets added an extensive land base with complementary infrastructures around Talisman's growing Edson area in central Alberta, as well as gas volumes produced at lower operating costs and a large number of development opportunities.

In August 2001, Talisman, through a direct wholly owned subsidiary, acquired Lundin Oil AB ("Lundin Oil"), a Swedish company with international oil and gas activities. The acquisition of Lundin Oil (which has been renamed Talisman Energy Sweden AB) provided Talisman with a new core area in Malaysia and Vietnam, additional interests in the North Sea and interests in Papua New Guinea.

In 2001, Talisman participated in major oil and gas discoveries offshore Trinidad. In 2002, Talisman expanded its interests both offshore and onshore Trinidad. In 2003, the Company began the Angostura development project, which is scheduled to continue through 2004 on offshore Block 2(c).

In May 2002, a consortium in which Talisman is a member was awarded Block 46/02, a three million acre exploration block offshore Vietnam. The award represented a key step in Talisman's strategy to grow its Vietnam/Malaysia business. In 2003, the Company began exploration drilling on this block. Also in 2003, the Company completed the PM-3 Commercial Arrangement Area ("PM-3 CAA") Phase 2/3 Development Project offshore Malaysia/Vietnam. Production began in September.

In October 2002, one of Talisman's indirect wholly owned subsidiaries acquired the producing Trenton-Black River natural gas assets and additional undeveloped lands of Fairman Drilling Company, FDC Venture 15, LP, East Resources, Inc. and ABARTA Oil & Gas Co., Inc. located in New York State. In January 2003, Talisman's indirect wholly owned subsidiary acquired additional natural gas properties, working interests, production and facilities relating to the Trenton-Black River play in New York State from Pennsylvania General Electric and Columbia Natural Resources. Through these acquisitions, the subsidiary broadened its exploration and development program in the area.

In March 2003, Talisman completed the sale of its indirect interest in the Greater Nile Oil Project in Sudan to ONGC Videsh Limited, a subsidiary of India's national oil company. An indirect subsidiary of Talisman had held a 25% interest in the Greater Nile Oil Project, which had been acquired in 1998. Additional information regarding the sale of the Sudan operations is contained in note 17 to the Company's audited consolidated financial statements for the year ended December 31, 2003 and in the Company's Management Discussion and Analysis incorporated herein by reference.

In September 2003, one of Talisman's indirect wholly owned subsidiaries acquired the operated interests and associated assets of BP Norge AS in the Gyda field of the Norwegian North Sea. In August 2003, a Talisman subsidiary was awarded four new exploration blocks in the UK North Sea, and later in the year another Talisman subsidiary was awarded two additional licenses in the Norwegian sector of the North Sea. This new acreage advances the Company's position in the area.

In July 2003, Talisman acquired various midstream assets in the Deep Basin area of northwestern Alberta when it purchased Vista Midstream Solutions Ltd. This strategic acquisition enhanced Talisman's ability to control its production, timing and costs in a highly competitive area.

Talisman continually investigates strategic acquisitions, dispositions and other business opportunities, some of which may be material. In connection with any such transaction, the Company may incur debt or issue equity securities.

DESCRIPTION OF THE BUSINESS

Talisman is one of the largest independent oil and gas producers in Canada. The Company's main business activities include exploration, development, production and marketing of crude oil, natural gas and natural gas liquids. Each of Talisman's current areas of operations has substantial exploration and development potential, which Talisman expects will provide for future growth.

North America

Talisman plans to spend approximately \$1.1 billion on exploration and development in Canada and the U.S. in 2004. Of this, over 77% is directed towards natural gas. The Company plans to participate in drilling approximately 640 gross wells in 2004.





Canada

Talisman's large North American gas business generates significant excess cash that is reinvested for growth both in Canada and abroad. In Canada, the Company's strategy is to continue natural gas exploration and development by focusing on deeper portions of the Western Canada Sedimentary Basin. Utilization of existing infrastructure and a high level of operatorship enable Talisman to maintain control over costs, production and capital spending. Talisman's diverse Canadian portfolio permits flexibility in responding to changing economic conditions. The Company's production growth has been achieved through drilling activities as well as through corporate and property acquisitions.

The Company focuses on divesting its non-strategic assets and acquiring producing properties complementary to existing core areas. Exploration and development activities have shifted to core gas properties to take advantage of Talisman's expertise in medium to deep areas of the basin. The focus of this activity will continue in the Greater Arch, Deep Basin, Alberta Foothills, Southern Alberta Foothills (formerly Turner Valley), Edson and Monkman areas.

Talisman's domestic exploration and development operations are organized around 14 core producing areas in Alberta, British Columbia, Ontario and Saskatchewan, which accounted for 89% of the Company's domestic production in 2003. The balance comprises production from joint venture properties and synthetic oil production from Talisman's indirect interest in the Syncrude joint venture. Of the 14 core areas, eight are dominated by gas production, namely: Greater Arch, Deep Basin, Alberta Foothills, Edson area (Edson, West Whitecourt and Bigstone/Wild River), Lac La Biche, Northern Plains, Monkman and Ontario offshore. Six core areas are dominated by oil production, namely: Chauvin, Carlyle, Central Alberta, Ontario onshore, Shaunavon and Southern Alberta Foothills (formerly Turner Valley). Within its core areas, Talisman operates approximately 81% of its production with high working interests in a large number of facilities.

Seven of the more active core properties accounted for approximately 72% of the Company's total domestic production in 2003: Greater Arch, Deep Basin, Alberta Foothills, Edson area, Monkman, Ontario (onshore and offshore) and Chauvin.

Greater Arch

The Greater Arch is Talisman's largest natural gas producing area. Adjacent to existing infrastructure, the Company has a large inventory of property interests to explore. Its average operated interest in oil and gas properties is 72%. Talisman holds operated interests ranging from 42% to 100% in gas plants at Teepee Creek, Belloy, Boundary Lake, George, Josephine and Shane, as well as interests in a number of other non-operated gas plants in the area. The Company plans to spend \$99 million in the Greater Arch in 2004 to participate in drilling approximately 67 wells.

Deep Basin

The Deep Basin is one of Talisman's new growth areas. Talisman holds 3% to 8% non-operated interests in the South Wapiti, Wapiti Deep Cut and Narraway gas plants. In July 2003, Talisman purchased Vista Midstream Solutions Ltd. to acquire the Cutbank facilities complex. The Cutbank complex consists of the Cutbank and Musreau gas plants, both with 100% working interests, five major field compression stations and an extensive gas gathering system. The acquisition enhances Talisman's ability to control its production, timing, capital costs and operating costs in this growth core area. Since 1999, the Deep Basin area has seen annual compound production growth rates of 25% reaching an annual record in 2003. The Company plans to spend \$103 million in the Deep Basin in 2004 to participate in drilling approximately 65 wells.

Alberta Foothills

Through exploration and development activity, the Alberta Foothills continues to be one of Talisman's fastest growing areas. Since 1999, the area's annual compound production growth rate has been 14%. Continued exploration in the northern Alberta Foothills has established Talisman as a significant player in the area. Major operated facilities include an 80% interest in the Cordel dehydration facility and associated pipelines, a 35% interest in the Chungo/Bighorn gas gathering system and a 45% interest in the Lovett River/Redcap Phase pipeline system. Talisman has non-operated interests ranging from approximately 8% to 34% in Basing, Voyager, Stolberg and Brown Creek pipelines and associated facilities. Completion of the Erith pipeline in November 2003 allowed egress of the Company's Alberta Foothills area to Talisman's midstream operations. The pipeline project consisted of a 75 mmcf/d dehydration facility, 69 kilometre of 10-inch diameter pipe, a flow splitter and enhanced sulphur recovery at the Edson plant. The connection of eight successful new gas wells enabled Talisman to set a new single day Alberta Foothills production record. Capital spending by the Company in the Alberta Foothills in 2004 is projected to be \$131 million, with plans to participate in drilling 30 wells.

Edson Area

Talisman's acquisitions of Petromet and midstream assets from TransCanada PipeLines Limited have rejuvenated growth in the Edson area through expanded development activity. Talisman is currently exploring and developing its acquired Bigstone/Wild River acreage. Talisman holds operated interests ranging from 56% to 100% in the Edson, Medicine Lodge, McLeod, Bigstone West and Wild River gas plants as well as non-operated interests ranging from 10% to 12% in the Kaybob South Amalgamated and the West Whitecourt gas plants. Capital spending by the Company in the Edson area in 2004 is projected to be \$249 million with plans to spend approximately \$45 million on infrastructure and participate in drilling approximately 103 wells. In the Edson core, there are plans to spend \$92 million, with plans to participate in drilling approximately 27 wells. In the Bigstone/Wild River area, the Company plans to spend \$112 million in 2004, with plans to participate in drilling approximately 46 wells. Capital spending by the Company in the West Whitecourt area in 2004 is projected to be \$45 million, with plans to participate in drilling approximately 30 wells.

The Company's 100% owned Central Foothills Gas Gathering System ("CFGGS"), Columbia Minehead Gas Gathering System ("CMGGS") and other midstream pipeline assets ranging from 75% to 100% ownership support the exploration and development program in both the Foothills and the Edson areas and also provide revenues from transportation and processing fees. The Company spent \$27 million to expand and optimize the CFGGS and CMGGS in 2003. The Erith pipeline, commissioned in the fourth quarter of 2003, routes gas from the Foothills area to the Edson and Hanlan-Robb sour gas plants, providing much needed egress from this growing area.

Monkman

In the Monkman area, the number of wells drilled and high success rate has made Talisman one of the major producers in the area. Talisman holds 58% to 100% operated interests in the Bullmoose, Sukunka and West Sukunka dehydration plants, 29% to 32% non-operated interests in the Murray River and Brazion dehydration plants and a 50% interest in the Mink Highhat pipelines. The successful commissioning of the Westcoast Acid Gas Reinjection Project is expected to facilitate greater throughput from existing, previously shut-in and future planned wells. Production was higher in 2003 than in 2002 due to successful drilling in the mature Triassic play. The Company's overall production is expected to remain flat until 2005, when gas production from the Deep Monkman Permian play is expected to increase total production in the area. Capital spending by the Company in this area in 2004 is projected to be \$76 million, with plans to participate in drilling approximately seven wells.

Ontario

Talisman is the largest oil and gas producer in Ontario with natural gas production in the offshore area of Lake Erie and oil production onshore. Talisman has a 100% interest in the Renwick, North Wheatley (East), Rochester and Hillman central facilities. In addition, Talisman has interests ranging from 65% to 100% in the Morpeth, Port Stanley, Port Alma, Port Maitland, Rochester and Nanticoke gas plants. Talisman's drilling program will continue in 2004, with plans to participate in drilling five onshore gas and oil wells and 15 offshore gas wells. Capital spending by the Company in Ontario in 2004 is expected to be \$13 million.

Chauvin

Chauvin is Talisman's largest domestic oil producing core property. High working interests characterize this area. With the acquisition of producing properties in the area and continued successful development activity, Talisman has achieved an annual compound production growth rate of 11% since 1999. Talisman holds a 100% interest in the Chauvin pipeline, which transports approximately 39 mmbbls/d of condensate blended crude and a 100% interest in the Chauvin Custom Treating Facility. The Company's expected 2004 capital program for Chauvin of \$38 million includes participation in drilling approximately 50 wells.

Other

Talisman is involved in a number of other projects in Canada. In Turner Valley, Alberta, a portion of the Southern Alberta Foothills core area, the Company commenced a nitrogen injection pilot project. This enhanced oil recovery project is the first of its kind in Canada. The Company is in the second of a three-year evaluation period to determine whether to expand the project to full-scale development. Talisman's interest in this experimental project is approximately 77%. In addition, the uphole gas play in the Turner Valley area was highly successful in 2003, with a number of new wells. To alleviate infrastructure bottlenecks, the Little Chicago Gas Plant was constructed in 2003 and commissioned in January 2004. Turner Valley gas rates are expected to double from 2003 volumes in March 2004. The Company's expected 2004 capital program for the Southern Alberta Foothills area is \$83 million including plans to participate in drilling approximately 21 wells.

In Carlyle, Warburg and South Central Alberta, Talisman continues its moderate capital spending on oil development.

The Company is also exploring the potential for producing coal bed methane on lands in Alberta and British Columbia. Appraisal drilling and prospect evaluation commenced in 2002. Capital spending by the Company in 2004 is projected to be approximately \$9 million, with plans to participate in drilling 33 gross wells.

In 2002, Talisman entered into a farm-in agreement with Imperial Oil Resources Ventures Ltd. to acquire a 30% interest in two exploration blocks in the deep-water Scotian Slope, southeast of Sable Island, Nova Scotia. The Company is evaluating the prospectivity of these blocks.

Synthetic Oil

Talisman holds a 1.25% indirect interest in the Syncrude oil sands project through the Canadian Oil Sands Limited Partnership. The Syncrude project is a joint venture established to recover shallow deposits of tar sands using open pit mining methods to extract the crude bitumen and to upgrade it to a high-quality, light (32 degree, API) sweet, synthetic crude oil. The Syncrude operation, located near Fort McMurray, Alberta, exploits portions of the Athabasca oil sands deposit to produce Syncrude Sweet Blend® ("SSB"). Syncrude is in the midst of a large expansion program. Stage 3 of the program is currently underway to expand productive capacity from the current level of 86 mmbbls per year to approximately 128 mmbbls per year after 2005. Since its start-up in 1978, Syncrude has produced almost 1.5 billion barrels of synthetic crude oil. In 2003, Syncrude shipped 77 mmbbls of SSB. Approximately 13% of Canada's crude oil needs are supplied by this joint venture. The Company's 2003 capital expenditures related to the Syncrude project, including expansion and sustaining capital, were approximately \$30 million.

United States

In the fourth quarter 2002 and during January 2003, Talisman's indirect wholly owned subsidiary, Fortuna Energy Inc. ("Fortuna"), initiated and expanded its New York interests through a number of property acquisitions. These acquisitions established Appalachia as Fortuna's first core gas area in the U.S. The acquired assets are in the deep Trenton-Black River gas play fairway. Its operated working interest is 100%. Fortuna plans to participate in drilling 11 wells in the area in 2004. Capital spending by the Company in this area in 2004 is expected to be approximately \$85 million.

Talisman's indirect wholly owned subsidiary, FUSI LLC, continues to focus on the western U.S. Capital spending by FUSI LLC in the U.S. in 2004 is expected to be \$14 million, with plans to participate in drilling three gross wells, two in Utah and one in Montana.

In June 2003, the Company's indirect wholly owned subsidiary, Fortuna Exploration LLC, entered into an agreement with Total E&P USA, Inc., under which the Company can earn a 30% interest in up to 360 square miles in the National Petroleum Reserve Area of the Alaskan North Slope through a rolling drilling option. This agreement established Talisman's first entry into Alaska. Early in 2004, the Company spudded its first Alaska exploration well. Capital spending is planned to be \$15 million in 2004.

Landholdings, Production and Producing Wells

The following tables set forth Talisman's North American landholdings, production and producing wells as at December 31, 2003.

Property	Undeveloped Acreage (thousand acres)		Developed Acreage (thousand acres)		Total Acreage (thousand acres)	
	Gross	Net	Gross	Net	Gross	Net
North America						
Canada						
Greater Arch	1,065.6	786.4	595.5	306.9	1,661.1	1,093.3
Deep Basin	435.6	242.4	216.4	45.1	652.0	287.5
Alberta Foothills	453.0	226.1	135.8	56.9	588.8	283.0
Edson Area	881.0	592.2	863.5	431.4	1,744.5	1,023.6
Monkman	546.5	342.2	96.1	47.4	642.6	389.6
Ontario	836.0	588.2	366.0	237.6	1,202.0	825.8
Chauvin	68.6	42.3	65.3	55.2	133.9	97.5
Other ¹	5,608.2	1,542.8	871.4	550.3	6,479.6	2,093.1
United States	1,038.0	883.8	11.5	11.5	1,049.5	895.3
Total²	10,932.5	5,246.4	3,221.5	1,742.3	14,154.0	6,988.7
Synthetic Oil	409.5	38.5	9.25	1.25	418.8	39.8

Notes:

1 "Other" includes properties in North America and Scotian Slope, but excludes synthetic oil in Alberta and coal leases in British Columbia.

2 Fee acreage comprises 7% of the total gross number of acres and 8% of net number of acres. Fee acreage for: Gross Undeveloped totals 620.1; Gross Developed totals 63.3; Net Undeveloped totals 443.0; and Net Developed totals 22.7.

Property	Oil & Liquids Production (bbls/d)		Natural Gas Production (mmcf/d)		Producing Wells as at December 31, 2003	
	Gross	Net	Gross	Net	Gross	Net
North America						
Canada						
Greater Arch	7,734	6,259	152.4	115.3	1,088	627.6
Deep Basin	1,735	1,581	50.9	35.7	403	68.4
Alberta Foothills	169	124	129.9	104.6	173	76.2
Edson Area	4,022	2,938	197.8	152.1	839	607.6
Monkman	—	—	86.6	69.6	56	32.2
Ontario	2,257	1,966	17.9	15.3	799	565.4
Chauvin	15,334	12,927	17.2	13.2	1,174	1,072.1
Other ¹	25,678	19,240	151.1	120.6	5,173	2,075.6
United States	—	—	59.9	51.6	28	28.0
Total	56,929	45,035	863.7	678.0	9,733	5,153.1
Synthetic Oil	2,649	2,510	—	—	—	—

Note:

1 "Other" includes producing properties in North America.

International

Talisman's international strategy concentrates on opportunities in sedimentary basins that have a proved hydrocarbon system and significant reserves and production potential. Talisman has developed its international business through exploration, development drilling and corporate and property acquisitions in all reporting segments.

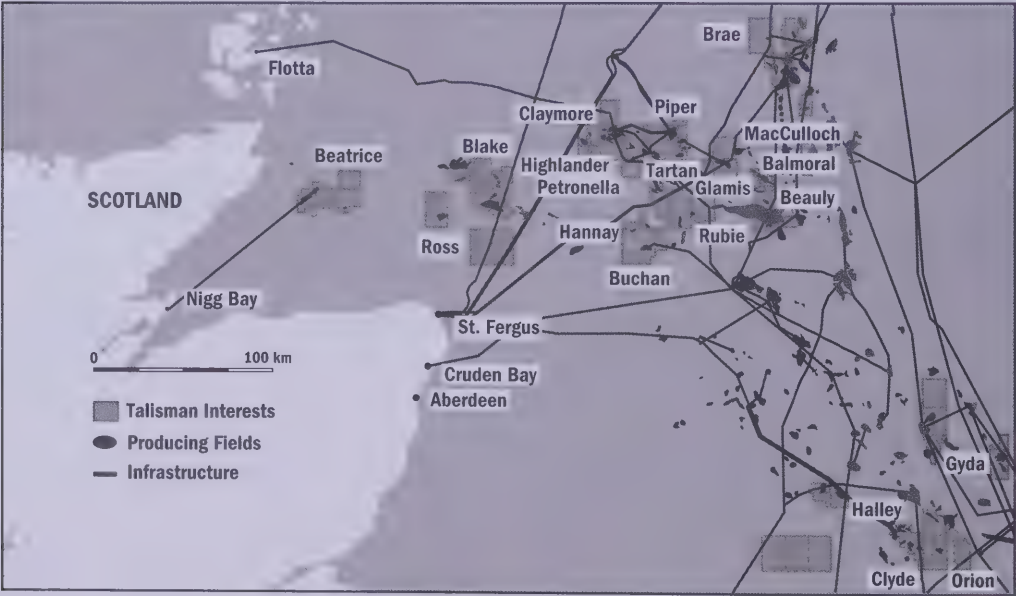
Talisman produces substantial oil and gas volumes from the North Sea, with ongoing exploration and development activities in the area. Talisman is also active in Southeast Asia, where development projects in Indonesia, Malaysia and Vietnam are expected to produce significant oil and gas production growth. Talisman also has a producing interest in Algeria, a development interest in Trinidad and exploration interests in other areas including Trinidad, Colombia, Qatar, Falkland Islands and Papua New Guinea.

North Sea

Talisman's North Sea strategy is to develop commercial hubs around core operated properties and infrastructure, and to deliver growth by extending the life of these assets through low risk development opportunities, sub-sea tie-back developments, nearby satellite exploration, secondary recovery, cost reduction and increased third-party tariff revenue. A portfolio of non-operated assets complements this strategy. Talisman is ranked sixth in UK North Sea liquids production and second in the Mid-North Sea in oil field operations as measured by the number of operated producing oil fields.

Talisman's North Sea assets, which are held principally by Talisman Energy (UK) Limited, Talisman North Sea Limited and Talisman Energy Norge AS, include producing fields and exploration acreage in several areas of the North Sea. Talisman has two core North Sea operating areas: the Mid-North Sea Area and the Flotta Catchment Area. Talisman also has an operated interest in the Norwegian sector of the North Sea. At the end of 2003, Talisman operated approximately 60% of its North Sea production.

In 2004, Talisman's capital program in the North Sea is expected to be approximately \$606 million, with \$119 million directed to exploration spending and \$487 million directed to development. The Company's 2004 North Sea drilling program includes participation in approximately eight exploration and 25 development wells.



Mid-North Sea Area

Talisman holds interests ranging from 12% to 100% in a number of production facilities and pipelines in the Mid-North Sea Area ("MNS").

Clyde Area

The Company owns various operated interests in the Clyde area, including a 95% operated interest in the Clyde production platform, a 94% operated interest in the Orion field, a 60% operated interest in the Halley field and a 13% non-operated interest in the Fulmar production platform. The Orion tie-back to Clyde was completed in 1999, and the Halley field started production in 2002. In 2003, Talisman drilled two development wells on the Clyde field and one on the Halley field. Talisman also participated in the Affleck exploration well near the Clyde field, which resulted in a new oil discovery. At the end of 2003, the Company was drilling the Eta-2 30/17b exploration well. Operations finished in January 2004 with the wellbore being plugged and abandoned. The 2004 development program includes water injection and produced water facility upgrades on the Clyde platform. Capital spending by the Company in the Clyde area in 2004 is expected to be \$52 million, with plans to participate in drilling three exploration wells, one of which was the aforementioned Eta-2 30/17b well.

Buchan Area

The Company has an average 86% operated working interest in the Buchan field, the Buchan floating production platform and the tie-in to the Forties pipeline. In March 2002, Talisman produced its first oil from the Hannay field where it operates with an 86% interest. In 2003, Talisman drilled a second development well on the Hannay field. In October 2002, Talisman drilled the J-1 exploration well and in November 2003, the J-5 exploration well, both resulting in new oil discoveries adjacent to the Buchan field. Talisman holds an 87% interest in the northern area of the block containing the discoveries. Development studies for J-1 and J-5 are underway. The Company's 2004 development program for the Buchan field includes a water injection project. Capital spending by the Company in 2004 in the Buchan area is expected to be \$220 million, with plans to participate in drilling one exploration well and to initiate the development of J-1 and J-5.

Ross/Blake Area

In the Ross/Blake area, Talisman has a 69% operated working interest in the Ross field and a 54% non-operated interest in the Blake field, both fields being sub-sea tie-backs to Bleo Holm, the leased Floating, Production, Storage and Offloading vessel ("FPSO"). In 2003, one development well was drilled on the Ross field and the Blake Flank pilot project was completed, with production commencing in September. Later in the year, a consortium, including Talisman (37.5%), was awarded Blocks 19/3 and 19/4 in the Twenty-first Licensing Round. These blocks are midway between the Ross field and the Buzzard discovery. Also in 2003, Talisman, as part of another consortium, was awarded Block 13/26b as an out-of-round award. Each of these newly awarded blocks involves a one-well commitment. Capital spending by the Company in 2004 in the Ross/Blake area is expected to be \$27 million, with plans to participate in drilling two exploration wells.

Beatrice Area

Talisman holds a 100% operated interest in the Beatrice Alpha, Bravo and Charlie platforms, as well as the Beatrice/Nigg pipeline and the Nigg terminal. A successful workover program was completed on Beatrice in early 2003. No capital spending is planned on the Beatrice oilfield in 2004.

Other Mid-North Sea Areas

Talisman holds a 60% operated interest in the Beaulieu field located in Block 16/21c of the MNS. Beaulieu is a sub-sea tie-back to the Balmoral field. No capital spending is planned for Beaulieu in 2004.

Flotta Catchment Area

Talisman holds interests ranging from 20% to 100% in a number of production facilities and pipelines in the Flotta Catchment Area ("FCA"), including a 60% interest in the Flotta terminal.

Piper Area

Talisman holds a 60% operated working interest in the Piper, Saltire, Chanter and Iona fields. In addition, Talisman has a 20% non-operated interest in the MacCulloch field. Capital spending by the Company in the Piper area is expected to be \$47 million in 2004. The Company plans to participate in drilling one exploration and one development well in the area in 2004.

Claymore Area

In the Claymore area, Talisman holds a 59% and a 60% operated working interest in the Claymore and Scapa fields, respectively. In 2003, Talisman drilled three development wells on the Claymore field and one exploration well at Dunnottar. The Dunnottar well did not yield commercial quantities of hydrocarbons. Capital spending by the Company in 2004 in the area is expected to be \$64 million, which includes funding for two development wells.

Tartan, Highlander and Petronella Areas

Talisman holds a 100% operated working interest in the Tartan field and the Highlander and Petronella sub-sea tie-back satellite fields ("THP"). In 2003, Talisman drilled the Tartan North Terrace B ("TNT-B") exploration well, making a new oil discovery adjacent to the Tartan field. Production from TNT-B is planned to commence in October 2004. Capital spending by the Company in the THP area is expected to be \$77 million in 2004, which includes participation in drilling one exploration and one development well.

Other Flotta Catchment Area Properties

Talisman holds a 78% and 41% operated working interest in the Renee and Rubie fields, respectively. Both fields are sub-sea tie-backs to the Ivanhoe/Rob Roy field in which Talisman has a 23% non-operated interest. In 2003, Talisman drilled one unsuccessful development well in the Ivanhoe/Rob Roy area. Further capital spending by the Company in this area is not planned at this time.

Norway

In the third quarter of 2003, Talisman acquired a 61% operated working interest in Licenses PL 019B and PL 019C, containing the Gyda field and platform facilities. Later in the year, Talisman was awarded Licenses PL 299 and PL 301. At the end of 2003, the Company was negotiating to purchase an interest in License 143 BS and 143 CS from ConocoPhillips Skandinavia AS, which has since been completed. These acquisitions provide the Company with potential growth opportunities within the Norwegian Continental Shelf. Capital spending by the Company in 2004 in the Norway area is expected to be \$63 million, with plans to participate in drilling three development wells.

Non-Operated Interest Properties

Brae Area

Talisman's non-operated interests in the Brae area range from 11% to 18%. Talisman also holds a 7% non-operated interest in the Brae-St. Fergus gas pipeline and terminal. The Brae complex is a low cost, long life asset. In 2003, Talisman participated in one development well in the Brae area and commenced production from the Braemar field. Also in 2003, a consortium including Talisman (18%) was awarded Block 16/1, adjacent to the Brae fields. This acquisition advances the Company's acreage position in the area. Capital spending by the Company in 2004 at Brae is expected to be \$10 million, with plans to participate in drilling one development well.

Other Non-Operated Interest Properties

Talisman holds various non-operated interests ranging from 2% to 20% including: Balmoral (15%), Stirling (15%), Glamis (15%), Andrew (3%), Wytch Farm (5%) and Wareham (5%). In 2003, Talisman acquired non-operated working interests in the Alba (2%) and Caledonia (3%) fields. In addition, Talisman holds non-operated interests in the Netherlands sector of the North Sea, including K4b/K5a (10%), K5b (20%) and E18a (4%). The 2004 program for the non-operated interest properties includes drilling one farm-in development well in the Cyrus field. Capital spending by the Company in 2004 is expected to be \$46 million, with plans to participate in drilling 17 development wells.

Landholdings, Production and Producing Wells

The following tables set forth Talisman's North Sea landholdings, production and producing wells as at December 31, 2003.

Property	Undeveloped Acreage (thousand acres)		Developed Acreage (thousand acres)		Total Acreage (thousand acres)	
	Gross	Net	Gross	Net	Gross	Net
Mid-North Sea Area						
Clyde Area	351.2	157.5	18.8	15.1	370.0	172.6
Buchan Area	200.6	111.1	3.7	3.2	204.3	114.3
Ross/Blake Area	309.3	186.6	17.2	10.5	326.5	197.1
Beatrice Area	98.9	78.4	11.0	11.0	109.9	89.4
Other MNS	16.1	9.7	—	—	16.1	9.7
Flotta Catchment Area						
Piper Area	91.1	51.0	28.7	14.2	119.8	65.2
Claymore Area	143.5	96.8	23.8	15.0	167.3	111.8
THP Area	152.3	85.3	14.5	14.5	166.8	99.8
Other FCA	13.5	3.8	15.6	7.7	29.1	11.5
Norway	342.0	203.6	33.9	20.7	375.9	224.3
Non-Operated Interests						
Brae Area	97.8	16.0	20.7	3.7	118.5	19.7
Other Non-Operated Interest ¹	300.2	36.3	224.3	24.3	524.5	60.6
Total	2,116.5	1,036.1	412.2	139.9	2,528.7	1,176.0

Note:

1 "Other Non-Operated Interest" includes the Netherlands.

Property	Oil & Liquids Production (bbls/d)		Natural Gas Production (mmcf/d)		Producing Wells as at December 31, 2003	
	Gross	Net ²	Gross	Net ²	Gross	Net
Mid-North Sea Area						
Clyde Area	13,014	13,027	4.4	4.4	18	16.7
Buchan Area	8,526	8,459	0.4	0.4	8	6.9
Ross/Blake Area	22,437	22,437	7.0	7.0	14	8.4
Beatrice Area	5,603	5,576	—	—	14	14.0
Other MNS	2,539	2,581	0.2	0.2	1	0.6
Flotta Catchment Area						
Piper Area	11,862	12,066	—	—	22	10.9
Claymore Area	18,692	19,239	—	—	30	17.7
THP Area	6,706	6,654	—	—	10	10.0
Other FCA	8,926	8,926	0.7	0.7	9	2.8
Norway	2,574	2,574	1.3	1.3	14	8.5
Non-Operated Interests						
Brae Area	7,883	7,331	83.6	76.7	52	7.1
Other Non-Operated Interest ¹	4,313	4,421	11.5	12.1	135	7.7
Total	113,075	113,291	109.1	102.8	327	111.3

Notes:

1 "Other Non-Operated Interest" includes the Netherlands.

2 Effective January 1, 2003 the UK abolished government royalties. Agreement was also reached on various outstanding UK royalty issues in respect of prior years, which also reduced the North Sea royalty expense in 2003. The effect of both events was for net production to exceed gross production.

Southeast Asia

The Company's interests in Southeast Asia include operations in Indonesia, Malaysia and Vietnam, as well as acreage in Papua New Guinea.



Indonesia

Talisman's strategy in Indonesia is the continued exploitation of existing oil properties and the development of the major natural gas discoveries at Corridor to deliver future production growth.

Talisman plans to spend approximately \$65 million in Indonesia in 2004, primarily to participate in drilling three exploration and five development wells and for the planned expansion of Corridor gas facilities.

Corridor PSC

Talisman (Corridor) Ltd. ("TCL"), an indirect wholly owned subsidiary of Talisman, has a 36% non-operated interest in the Corridor production sharing contract ("Corridor PSC Block") and field production facilities.

In the Corridor PSC Block, TCL's gas sales to PT Caltex Pacific Indonesia ("Caltex") commenced in 1998 to the Duri steam flood project. Talisman Transgasindo Ltd. has an indirect 6% interest in the Grissik to Duri pipeline and a right to acquire an indirect 6% interest in the new 474 kilometre pipeline from Grissik to Singapore completed in 2003.

In September 2003, TCL commenced gas sales to Gas Supply Pte. Ltd., located in Singapore, under the terms of the 20-year gas sales agreement entered into in February 2001.

The focus of TCL's gas strategy is to deliver further production growth through the development of the Suban and other gas fields via the Suban Phase 2 expansion to enable sales to West Java and other markets. The Suban Phase 2 project is planned to commence in 2004 and involves the installation of two new 200 mmcf/d capacity gas trains, additional pipelines and infrastructure in the Corridor PSC. In July 2003, a heads of agreement was entered into with PT PLN (Persero) (Indonesia's state owned electric power generation company) for major gas sales from the Corridor PSC Block to markets in West Java. Gas deliveries could start as early as 2006 and reach plateau rates in approximately 2011. TCL also expects to start gas sales to industrial users and for power generation on Batam Island in 2004 and reach plateau rates by around 2009. Commercial arrangements are also being negotiated for the sale of further Corridor PSC Block gas to other markets. Further development drilling at Suban is planned in 2005 and 2006 to service West Java and the other potential gas contracts.

In 2004, Talisman expects its capital spending in the area to be approximately \$51 million. The Company plans to participate in drilling one exploration well.

Other Properties

Talisman and its subsidiaries hold a 40% non-operated interest in the Corridor technical assistance contract (the "Corridor TAC Block"), a 20% non-operated interest in the Jambi enhanced oil recovery contract (the "Jambi Block"), a 25% non-operated interest in the Madura Offshore production sharing contract (the "Madura Block"), a 50% operated interest in the Ogan Komering production sharing contract (the "OK Block") and a 50% operated interest in the Tanjung Raya enhanced oil recovery contract (the "Tanjung Block"). As a result of Talisman continuing to fund the share of expenditures of Perusahaan Pertambangan Minyak Dan Gas Bumi Negara, Indonesia's national oil company, in the Jambi and Tanjung Blocks, the Company records working interests in these Blocks of 40% and 100%, respectively. In 2003, pursuant to the terms of a farm-in agreement, Talisman earned a 25% non-operated interest in the Nila production sharing contract (the "Nila Block").

The 2004 program includes drilling two development wells on the OK Block, three development wells on the Corridor TAC Block and continued fracture stimulations on the Tanjung Block. Talisman has also committed to participate in drilling one exploration well on each of the Nila Block and the OK Block. In January 2004, a heads of agreement was entered into with PT Perusahaan Gas Negara (Persero) Tbk for the sale of gas from the Madura Block. Talisman's rights in respect of the Tanjung Block and Jambi Block are due to expire in November 2004 and January 2005, respectively.

Capital spending by the Company in 2004 is expected to be \$14 million.

Malaysia and Vietnam

In Malaysia and Vietnam, the Company's strategy is to develop oil and natural gas fields in its core operated blocks and to deliver production growth through exploration and development. The Company operates all of its working interest properties in Malaysia and Vietnam except Block 46/02, which is operated by a joint operating company. Total Malaysia and Vietnam capital spending is expected to be \$250 million, most of which will be directed to three key areas.

Block PM-3 CAA and 46-Cai Nuoc

Two of Talisman's indirect wholly owned subsidiaries hold interests in the PM-3 CAA and associated production facilities in Malaysia and Vietnam: Talisman Malaysia Limited (26.4%) and Talisman Malaysia (PM3) Limited (15%). Talisman Vietnam Limited, another indirect wholly owned subsidiary, holds a 33.2% operated interest in the adjacent Block 46-Cai Nuoc area in Vietnam. Part of that area and part of the PM-3 CAA were unitized in 1998 to become the East Bunga Kekwa-Cai Nuoc unit.

In 2003, the Company completed Phase 2/3 of the PM-3 CAA Project, developing a number of fields located in the southeast portion of the block. The project involved the installation of four new wellhead platforms, a central processing platform, a compression annex platform, a floating storage offloading vessel and interfield pipelines. The Phase 2/3 facilities have a production capacity of 60 mbbls/d of liquids and 270 mmcf/d of gas. The Phase 2/3 project was completed on budget and on time with oil production starting in September 2003 and natural gas in late 2003. Natural gas is sold under a long-term contract to Petrolim Nasional Berhad and Vietnam Oil and Gas Corporation, the national oil and gas companies of Malaysia and Vietnam, respectively.

In 2003, the Company had a successful exploration program in the PM-3 CAA and Block 46-Cai Nuoc areas. Out of four exploration wells drilled the Company made three hydrocarbon discoveries. The Company also drilled two successful appraisal wells in the area.

Capital spending by the Company in this area in 2004 is expected to total approximately \$160 million, with plans to participate in drilling one exploration well and 30 development wells.

Block PM-305

Talisman Malaysia Limited holds a 60% operated working interest in Block PM-305 production sharing contract offshore Malaysia, approximately 250 kilometres southeast of Block PM-3 CAA. In 2003, the Company made an oil discovery 10 kilometres south of the Angsi field. The South Angsi-1 exploration well discovered oil in two reservoir intervals. Two side-track wells, drilled north and south of the discovery, defined the limits of the field. The South Angsi field is fully appraised and development is underway. First production is expected in mid-2005.

Capital spending by the Company in this area in 2004 is expected to total approximately \$63 million, with plans to participate in drilling two exploration and two development wells.

Block 46/02

In December 2002, Talisman (Vietnam 46/02) Ltd. signed a Petroleum Contract for a 30% interest in Block 46/02 in Vietnam. Talisman (Vietnam 46/02) Ltd. holds a 30% interest in the Truong Son Joint Operating Company ("JOC"), with the remainder held by PetroVietnam Exploration and Production Company (40%) and Petronas Carigali Overseas SDN BHD (30%), the wholly owned exploration and production subsidiaries of the national petroleum companies of Vietnam and Malaysia, respectively. In 2003, the JOC drilled its first exploration well since being awarded the block. The Song Doc-1X oil discovery well is located 13 kilometres northwest of the PM-3 CAA Bunga Kekwa C wellhead platform. Capital spending by the Company in Block 46/02 in 2004 is expected to total approximately \$17 million. The Company plans to participate in drilling two exploration wells.

Papua New Guinea

The Company acquired an operated interest in offshore Papua New Guinea Block PPL-200 (35%) and Block PRL-1 (48%) through a corporate acquisition in 2001. Block PPL-200 was relinquished in 2003. Block PRL-1 contains a natural gas discovery. Further exploration and appraisal work will be contingent on the advancement of possible pipeline projects.

Landholdings, Production and Producing Wells

The following tables set forth Talisman's Southeast Asia landholdings, production and producing wells as at December 31, 2003.

Property	Undeveloped Acreage (thousand acres)		Developed Acreage (thousand acres)		Total Acreage (thousand acres)	
	Gross	Net	Gross	Net	Gross	Net
Indonesia						
Corridor PSC	407.6	146.8	150.5	54.2	558.1	201.0
Other ¹	2,390.4	670.6	142.1	72.9	2,532.5	743.5
Malaysia and Vietnam						
PM-3 CAA and 46-Cai Nuoc	14.3	4.8	224.4	92.5	238.7	97.3
PM-305	543.6	326.2	—	—	543.6	326.2
46/02	3,023.6	907.1	—	—	3,023.6	907.1
Papua New Guinea						
	187.3	90.2	—	—	187.3	90.2
Total	6,566.8	2,145.7	517.0	219.6	7,083.8	2,365.3

Note:

1 "Other" includes the Corridor TAC Block, Tanjung Block, Jambi Block, OK Block and Madura Block.

Property	Oil & Liquids Production (bbls/d)		Natural Gas Production (mmcf/d)		Producing Wells as at December 31, 2003	
	Gross	Net ¹	Gross	Net ¹	Gross	Net
Indonesia						
Corridor PSC	2,543	2,208	105.3	101.0	57	20.3
Other ²	13,215	6,688	6.8	5.0	461	226.5
Malaysia and Vietnam						
PM-3 CAA and 46-Cai Nuoc	8,672	5,957	5.0	4.0	25	10.1
PM-305	—	—	—	—	—	—
46/02	—	—	—	—	—	—
Papua New Guinea						
	—	—	—	—	—	—
Total	24,430	14,853	117.1	110.0	543	256.9

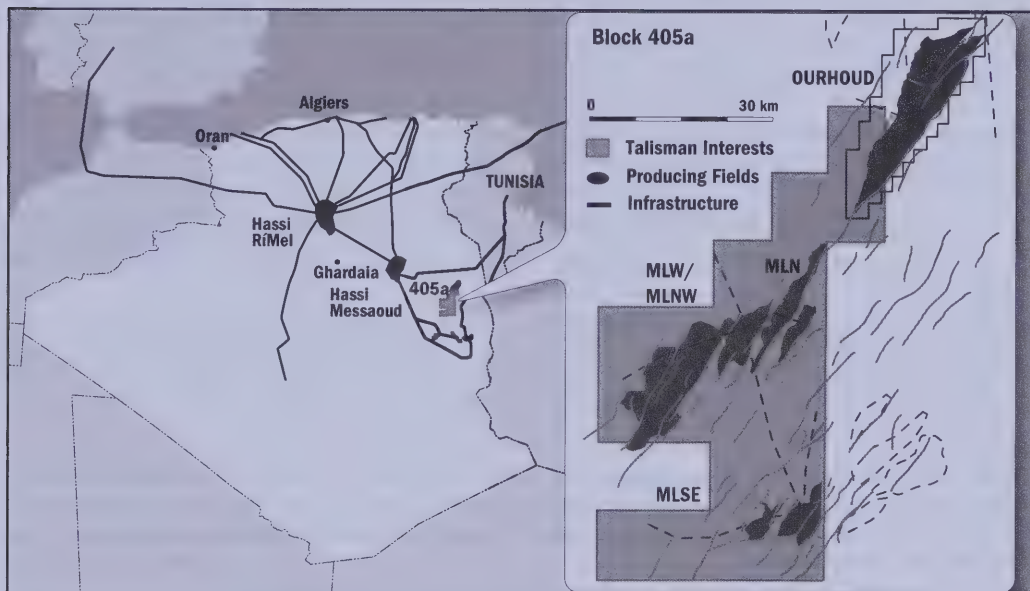
Notes:

1 Interests of the Indonesian, Malaysian and Vietnam governments, other than working interests or income taxes, are accounted for as royalties.

2 "Other" includes the Corridor TAC Block, Tanjung Block, Jambi Block, OK Block and Madura Block.

Algeria

Talisman (Algeria) B.V., an indirect wholly owned subsidiary of Talisman, holds a 35% non-operated working interest in Blocks 215 and 405a under production sharing contract with Algeria's National Oil Company SONATRACH ("Sonatrach"). Block 405a contains the Greater Menzel Lejmat North ("Greater MLN") development project as well as a portion of the Ourhoud field.



Greater MLN

During 2003, Phase 1 of the Greater MLN development project was completed with a production capacity of 35 mbbls/d. Production from the Greater MLN field in the northern portion of the block started in June 2003. Additional production from the nearby Greater MLN satellite oilfields commenced in December 2003. Greater MLN facilities include a central processing facility ("CPF") and compression for gas injection. Crude oil is exported to the Mediterranean coast. The Phase 2 expansion of the CPF is planned for 2004/2005 and will include the installation of new facilities to increase production capacity. Development planning for the Menzel Lejmat South East ("MLSE") field located to the south of Block 405a is currently underway.

Ourhoud

Production at the Ourhoud field (Talisman 2%) commenced in December 2002 with first oil sales in 2003. Water injection is proceeding successfully. Production from Ourhoud is anticipated to remain at plateau levels throughout 2004.

In 2004, Talisman plans capital spending of approximately \$44 million in Algeria, which includes funding for the drilling of 10 development wells at Ourhoud and six development wells in the Greater MLN area.

Landholdings, Production and Producing Wells

The following tables set forth Talisman's Algerian landholdings, production and producing wells as at December 31, 2003.

Property	Undeveloped Acreage (thousand acres)		Developed Acreage (thousand acres)		Total Acreage (thousand acres)	
	Gross	Net	Gross	Net	Gross	Net
Greater MLN¹	330.5	115.7	11.2	3.9	341.7	119.6
Ourhoud	—	—	65.6	1.3	65.6	1.3
Other²	420.0	147.0	—	—	420.0	147.0
Total	750.5	262.7	76.8	5.2	827.3	267.9

Notes:

1 "Greater MLN" includes MLSE acreage.

2 "Other" includes Block 215 acreage.

Property	Oil & Liquids Production (bbls/d)		Natural Gas Production (mmcf/d)		Producing Wells as at December 31, 2003	
	Gross	Net ¹	Gross	Net ¹	Gross	Net
Greater MLN	3,059	1,613	—	—	12	4.2
Ourhoud	3,535	1,738	—	—	23	0.5
Total	6,594	3,351	—	—	35	4.7

Note:

1 Interests of the Algerian government, other than working interests or income taxes, are accounted for as royalties.

Trinidad

Talisman holds interests in two blocks in the offshore shallow water to the northeast of Trinidad. This includes a 25% non-operated interest in the Angostura development portion of Block 2(c) and a 36% interest in the balance of Block 2(c) located to the south and retained for further exploration. The 36% interest is comprised of a 25% original interest plus an 11% share of the interest of a non-participating co-venturer, subject to a reinstatement right.

The Greater Angostura Project located in Block 2(c) was sanctioned in 2003 and the oil and gas development is progressing as planned. The installation of the K-2 platform was completed in October 2003. Planned project activity in 2004 includes a continuous development drilling program and the fabrication and installation of the remaining field facilities, including a central processing platform and three further wellhead platforms. Crude oil will be exported via an 18-inch liquids pipeline to a new onshore oil terminal located at Galeota Point in the southeast of Trinidad. First production from the project is planned for early 2005. In 2003, a new hydrocarbon discovery was made on the retained exploration portion of Block 2(c) when the Company participated in one exploration well.

Talisman's wholly owned subsidiary, Talisman (Trinidad Block 3a) Ltd., holds a 30% interest in the production sharing contract on Block 3(a), immediately to the east of Block 2(c). There is a six well commitment related to Block 3(a), of which two wells have been drilled. A third exploration well was underway at year end. All three wells on this block have made hydrocarbon discoveries.

In 2002, Talisman (Trinidad) Petroleum Ltd., a wholly owned subsidiary, acquired the right to earn an operated 65% interest in the onshore Eastern Block. This block is comprised of approximately 108 thousand gross acres (44 thousand hectares), of which the Government of Trinidad holds the mineral rights to approximately 95 thousand acres (38.5 thousand hectares) and the balance are freehold title. There is a three well commitment related to the Eastern Block. In 2004, the Company expects to complete its acquisition of 3D seismic covering much of the Eastern Block. First exploration drilling is anticipated for 2005.

Trinidad capital spending in 2004 is planned to be approximately \$170 million. Planned activity includes four exploration and appraisal wells, the completion of onshore seismic operations and participation in drilling 15 development wells as part of the Angostura project.

Colombia

In Colombia, Talisman (Colombia) Oil & Gas Ltd., a wholly owned subsidiary of Talisman, is focusing on an exploration program in a known hydrocarbon basin. As a result of a series of transactions commencing in December 2000, Talisman's subsidiary currently holds non-operated interests in five blocks in Colombia. In the Upper Magdalena Valley region, the subsidiary holds a 70% interest in the Acevedo Block and a 30% interest in both the Altamizal and Huila Norte blocks. A required relinquishment of a portion of the Huila Norte block in 2004 will reduce Talisman's subsidiary's hectorage from approximately 48 thousand hectares to a proposed 24 thousand hectares in Huila Norte. In the Llanos Foothills region of north-central Colombia, the subsidiary holds a 30% interest in the Tangara and Mundo Nuevo blocks, which are adjacent to the large Cusiana/Cupiagua oil fields. During 2004, relinquishments other than that on the Huila Norte block may occur in Colombia pending evaluation of recently drilled wells, but none are planned at this time.

In 2003, Talisman participated in two exploration wells in Colombia: the El Encanto-2 well on the Huila Norte Block and the Candelo-1 well on the Acevedo Block. Both wells drilled over year end and were subsequently plugged and abandoned. Technical work is currently underway to determine the next exploration phase on the Altamizal, Acevedo and Huila Norte blocks.

Capital spending by the Company's subsidiary in Colombia in 2004 is expected to total approximately \$28 million. There are plans to participate in drilling one exploration well.

Qatar

Talisman Energy (Qatar) Inc., a wholly owned subsidiary of Talisman, signed an Exploration and Production Sharing Agreement for offshore Block 10 in Qatar in November 2002. Talisman Energy (Qatar) Inc. holds a 100% interest in the agreement, which was ratified by official decree of the Emir of Qatar in April 2003. Geophysical work began in 2003 and is planned to continue throughout 2004, in support of an obligation to drill three exploration wells over the next four years.

Capital spending by the Company's subsidiary in 2004 is expected to total approximately \$8 million, primarily to fund the ongoing geophysical work program.

Other

Talisman's strategy is to expand activity in core producing areas and to add new ventures where appropriate. The Company actively investigates new ventures outside core producing areas.

Productive Wells and Acreage

The following table shows the number of productive wells and wells capable of production in which the Company had a working interest, as well as developed and undeveloped acres assignable to such wells, as of December 31, 2003. Undeveloped acreage is considered to be those lease acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas regardless of whether or not such acreage contains proved reserves.

	Productive Wells		Developed	Undeveloped
	Oil Wells ²	Gas Wells ²	Acres	Acres
North America³				
Gross	5,409.0	4,324.0	3,230.9	11,342.1
Net	2,841.2	2,311.9	1,743.5	5,284.9
North Sea				
Gross	307.0	20.0	412.1	2,116.6
Net	109.7	1.6	139.9	1,036.0
Southeast Asia				
Gross	521.0	22.0	517.0	6,567.3
Net	248.8	8.1	219.6	2,145.5
Algeria				
Gross	35.0	—	76.8	750.5
Net	4.7	—	5.2	262.7
Trinidad				
Gross	—	—	—	323.3
Net	—	—	—	136.0
Other¹				
Gross	—	—	—	2,421.6
Net	—	—	—	1,577.6
Total				
Gross	6,272.0	4,366.0	4,236.8	23,521.4
Net	3,204.4	2,321.6	2,108.2	10,442.7

Notes:

1 "Other" includes Colombia, Qatar, Falkland Islands.

2 Includes wells containing multiple completions as follows:

	Oil Wells	Gas Wells
Gross	830.0	1,263.0
Net ¹	329.5	581.4

3 "North America" includes synthetic oil.

Drilling Activity

The following table sets forth the number of wells¹ Talisman has drilled and tested or participated in drilling and testing, and the net² interest of the Company in such wells for each of the last three fiscal years. The number of wells drilled refers to the number of wells completed at any time during the fiscal years, regardless of when drilling was initiated. The term "completion" refers to the installation of permanent equipment for the production of oil and gas, or, in the case of a dry hole, to reporting of abandonment to the appropriate agency.

Year Ended December 31, 2003		Exploration				Development				Total			
		Oil ³	Gas ³	Dry ⁴	Total	Oil ³	Gas ³	Dry ⁴	Total	Oil ³	Gas ³	Dry ⁴	Total
North America													
Canada ⁵	Gross	14.0	147.0	22.0	183.0	190.0	225.0	21.0	436.0	204.0	372.0	43.0	619.0
	Net	9.4	100.9	15.9	126.2	101.0	132.7	18.2	251.9	110.4	233.6	34.1	378.1
United States	Gross	—	6.0	—	6.0	—	—	—	—	—	6.0	—	6.0
	Net	—	4.2	—	4.2	—	—	—	—	—	4.2	—	4.2
North Sea⁶													
	Gross	3.0	—	2.0	5.0	12.0	2.0	3.0	17.0	15.0	2.0	5.0	22.0
	Net	2.2	—	1.1	3.3	5.5	0.2	0.9	6.6	7.7	0.2	2.0	9.9
Southeast Asia													
Indonesia	Gross	—	1.0	2.0	3.0	6.0	—	—	6.0	6.0	1.0	2.0	9.0
	Net	—	0.4	0.5	0.9	2.6	—	—	2.6	2.6	0.4	0.5	3.5
Malaysia/ Vietnam	Gross	2.0	4.0	1.0	7.0	12.0	9.0	—	21.0	14.0	13.0	1.0	28.0
	Net	0.9	1.6	0.4	2.9	4.9	3.6	—	8.5	5.8	5.2	0.4	11.4
Algeria	Gross	1.0	—	—	1.0	11.0	—	—	11.0	12.0	—	—	12.0
	Net	0.4	—	—	0.4	0.6	—	—	0.6	1.0	—	—	1.0
Sudan	Gross	2.0	—	—	2.0	1.0	—	—	1.0	3.0	—	—	3.0
	Net	0.5	—	—	0.5	0.3	—	—	0.3	0.8	—	—	0.8
Trinidad	Gross	1.0	2.0	—	3.0	—	—	—	—	1.0	2.0	—	3.0
	Net	0.4	0.6	—	1.0	—	—	—	—	0.4	0.6	—	1.0
Total	Gross	23.0	160.0	27.0	210.0	232.0	236.0	24.0	492.0	255.0	396.0	51.0	702.0
	Net	13.8	107.7	17.9	139.4	114.9	136.5	19.1	270.5	128.7	244.2	37.0	409.9

Year Ended December 31, 2002 ⁷		Exploration				Development				Total			
		Oil ³	Gas ³	Dry ⁴	Total	Oil ³	Gas ³	Dry ⁴	Total	Oil ³	Gas ³	Dry ⁴	Total
North America													
Canada	Gross	17.0	95.0	35.0	147.0	129.0	127.0	15.0	271.0	146.0	222.0	50.0	418.0
	Net	14.8	66.4	26.4	107.6	88.9	70.9	10.9	170.7	103.7	137.3	37.3	278.3
United States	Gross	—	1.0	5.0	6.0	—	—	—	—	—	1.0	5.0	6.0
	Net	—	1.0	3.4	4.4	—	—	—	—	—	1.0	3.4	4.4
North Sea⁶													
	Gross	1.0	—	3.0	4.0	14.0	2.0	3.0	19.0	15.0	2.0	6.0	23.0
	Net	0.9	—	1.6	2.5	5.4	0.1	2.2	7.7	6.3	0.1	3.8	10.2
Southeast Asia													
Indonesia	Gross	—	3.0	2.0	5.0	5.0	—	1.0	6.0	5.0	3.0	3.0	11.0
	Net	—	0.9	1.0	1.9	2.5	—	0.4	2.9	2.5	0.9	1.4	4.8
Malaysia/ Vietnam	Gross	1.0	1.0	2.0	4.0	2.0	—	—	2.0	3.0	1.0	2.0	6.0
	Net	0.4	0.4	0.8	1.6	0.8	—	—	0.8	1.2	0.4	0.8	2.4
Algeria	Gross	—	—	—	—	8.0	—	—	8.0	8.0	—	—	8.0
	Net	—	—	—	—	0.8	—	—	0.8	0.8	—	—	0.8
Sudan	Gross	16.0	—	7.0	23.0	6.0	—	1.0	7.0	22.0	—	8.0	30.0
	Net	4.0	—	1.8	5.8	1.5	—	0.3	1.8	5.5	—	2.1	7.6
Trinidad	Gross	2.0	1.0	2.0	5.0	—	—	—	—	2.0	1.0	2.0	5.0
	Net	0.5	0.3	0.9	1.7	—	—	—	—	0.5	0.3	0.9	1.7
Total	Gross	37.0	101.0	56.0	194.0	164.0	129.0	20.0	313.0	201.0	230.0	76.0	507.0
	Net	20.6	69.0	35.9	125.5	99.9	71.0	13.8	184.7	120.5	140.0	49.7	310.2

Year Ended December 31, 2001 ⁷		Exploration				Development				Total			
		Oil ³	Gas ³	Dry ⁴	Total	Oil ³	Gas ³	Dry ⁴	Total	Oil ³	Gas ³	Dry ⁴	Total
Canada	Gross	27.0	100.0	38.0	165.0	231.0	141.0	17.0	389.0	258.0	241.0	55.0	554.0
	Net	23.0	63.0	30.2	116.2	137.7	74.2	10.6	222.5	160.7	137.2	40.8	338.7
North Sea⁶	Gross	3.0	3.0	4.0	10.0	20.0	—	3.0	23.0	23.0	3.0	7.0	33.0
	Net	2.1	0.3	1.6	4.0	8.8	—	0.4	9.2	10.9	0.3	2.0	13.2
Southeast Asia													
Indonesia	Gross	1.0	3.0	4.0	8.0	49.0	—	8.0	57.0	50.0	3.0	12.0	65.0
	Net	0.4	1.1	1.6	3.1	19.6	—	3.1	22.7	20.0	1.1	4.7	25.8
Malaysia/ Vietnam	Gross	1.0	—	1.0	2.0	1.0	—	—	1.0	2.0	—	1.0	3.0
	Net	0.4	—	0.6	1.0	0.4	—	—	0.4	0.8	—	0.6	1.4
Algeria	Gross	3.0	1.0	2.0	6.0	8.0	—	—	8.0	11.0	1.0	2.0	14.0
	Net	1.1	0.4	0.7	2.2	0.8	—	—	0.8	1.9	0.4	0.7	3.0
Sudan	Gross	16.0	—	5.0	21.0	23.0	—	—	23.0	39.0	—	5.0	44.0
	Net	4.0	—	1.3	5.3	5.8	—	—	5.8	9.8	—	1.3	11.1
Trinidad	Gross	2.0	—	1.0	3.0	—	—	—	—	2.0	—	1.0	3.0
	Net	0.5	—	0.5	1.0	—	—	—	—	0.5	—	0.5	1.0
Total	Gross	53.0	107.0	55.0	215.0	332.0	141.0	28.0	501.0	385.0	248.0	83.0	716.0
	Net	31.5	64.8	36.5	132.8	173.1	74.2	14.1	261.4	204.6	139.0	50.6	394.2

Notes:

1 The number of wells refers to gross wellbores, which is the total number of wells Talisman has drilled or participated in drilling, with a working interest. Service wells, including water injection, gas injection, water source and water disposal wells are not included. Multilaterals from the same wellbore are counted as a single wellbore.

2 "Net" wellbores are the aggregate of the percentage working interest of the Company in each of the gross wellbores. Data is rounded to the nearest decimal place and summed.

3 A productive oil or gas well is an exploratory or development well that is not a dry well. "Oil" includes bitumen.

4 A dry hole is an exploratory or a development well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

5 "Canada" includes the Scotian Slope well.

6 "North Sea" for 2003, includes the United Kingdom, Norway and the Netherlands Continental Shelf and for 2002 and 2001, includes the United Kingdom and the Netherlands Continental Shelf.

7 As discussed under the heading "Note Regarding Reserves Data and Other Oil and Gas Information", in 2003 Talisman began stating oil and gas information in accordance with U.S. disclosure requirements. These requirements have been applied to prior year drilling statistics, resulting in some changes to figures previously reported for the years ended December 31, 2001 and December 31, 2002.

The following table shows the number of wells in the process of drilling or in active completion stages as of December 31, 2003.

	Wells in the process of drilling, suspended or active completion	
	Exploration	Development
North America		
Gross	142.0	220.0
Net	101.2	137.1
North Sea		
Gross	1.0	4.0
Net	1.0	1.2
Southeast Asia		
Gross	2.0	4.0
Net	0.8	1.6
Algeria		
Gross	—	1.0
Net	—	—
Trinidad		
Gross	1.0	1.0
Net	0.3	0.3
Other¹		
Gross	2.0	—
Net	1.0	—
Total		
Gross	148.0	230.0
Net	104.3	140.2

Note:

1 "Other" includes Colombia.

Reserves Estimates

Talisman's oil and gas reserves are evaluated internally. The exemption under NI 51-101 described under "Note Regarding Reserves Data and Other Oil and Gas Information", in addition to permitting Talisman to provide disclosure in accordance with U.S. standards, exempts Talisman from the requirement under NI 51-101 to have its reserves evaluated or audited by independent reserves evaluators. NI 51-101 and its companion policy specifically contemplate the granting of such an exemption to issuers such as Talisman who produce over 100,000 boe/d and are able to demonstrate the internal capability to generate reliable reserves data. The following discussion is provided pursuant to the requirements of the exemption.

Talisman understands that the purpose of the requirement under NI 51-101 for the involvement of independent qualified evaluators or auditors is to ensure that disclosure of reserves information reflects the conclusions of qualified professionals applying consistent standards and that such conclusions are not affected by adverse influences. Talisman believes that using independent evaluators or auditors would not materially enhance the reliability of its reserves estimates, in light of the expertise of its internal reserves evaluation personnel and the controls applied during its reserves evaluation process. Talisman believes that its internal resources are at least as extensive as, if not greater than, those which would be assigned by any independent evaluators or auditors engaged by the Company, and that its internal staff's knowledge of and experience with the Company's reserves enable the Company to prepare an evaluation at least equivalent to that of any independent evaluator or auditor.

As at December 2003, the Company's internal reserves evaluation staff included 90 persons with full-time or part-time responsibility for reserves evaluation with an average of approximately 15 full-time or part-time years of relevant experience in evaluating reserves, of whom 52 were "qualified reserves evaluators" for purposes of NI 51-101. The Company's internal reserves evaluation management personnel included approximately 24 persons with full-time or part-time responsibility for reserves evaluation management with an average of approximately 21 full-time or part-time years of relevant experience in evaluating and managing the evaluation of reserves, 14 of whom were qualified reserves evaluators for purposes of NI 51-101. The Company has appointed an Internal Qualified Reserves Evaluator ("IQRE") who reports directly to the Chief Executive Officer and who is responsible for the preparation and validation of the Company's reserves evaluation and the submission to the Company's Board of Directors of a report thereon as required by the NI 51-101 exemption. The Company's IQRE is Michael Adams, a graduate of Imperial College, London University with a B.Sc. in Physical Chemistry and an M.Sc. in Petroleum Engineering. Mr. Adams has over 30 years of petroleum engineering experience internationally and in North America. He is a professional engineer registered in Alberta and a chartered engineer registered in the UK.

Talisman has adopted a corporate policy which prescribes procedures and standards to be followed in preparing its reserves data. The following summarizes Talisman's current process for preparing and approving its publicly disclosed reserves data.

- All of Talisman's proved reserves are evaluated annually. Talisman employs qualified, competent, experienced engineers to ensure consistently high levels of professionalism in the estimation of its reserves data. Technical, cost and economic assumptions underpinning reserves estimates are documented to provide a clear audit trail.
- Talisman conducts formal reviews during the proved reserves estimation process to ensure: the reasonableness, completeness and accuracy of input data; the appropriateness of the technical sub-surface methodology; the full understanding of reserve movements; and the correct use of reserves classifications. Peer review of input data and results is also common practice. All reserve estimates are reviewed and approved by the Executive Vice-Presidents of the operating areas and then submitted to the Company's executive operating committee, comprised of the Chief Executive Officer and all the Executive Vice-Presidents of the Company, for review and approval. In addition, the IQRE conducts a separate review to ensure the effectiveness of the disclosure controls and that the reserves estimates are free from material misstatement. The reserves data and the report of the IQRE are then reviewed by the Reserves Committee of the Board of Directors. The Reserves Committee and the IQRE have independent access to each other. Once approved by the Reserves Committee, the reserves data is submitted to the Board of Directors for final approval.
- Notwithstanding that Talisman is exempt from the independent evaluator requirements of NI 51-101, Talisman obtains annual audits by independent external engineering consultants of its reserve estimates for some of its properties on a rotating basis. Over the past three years, the Company's estimates for approximately 90% of its current proved reserves (on a boe basis) have been independently audited. The audits have not revealed any material discrepancies. External engineering consultants also reviewed Talisman's Reserves Data Policy and Procedures Manual in 2003. They concluded that the Policy and Procedures Manual for reserves data is consistent with U.S. and Canadian regulatory requirements, utilize evaluation practices and procedures based on the Canadian Oil and Gas Evaluation Handbook modified to the extent necessary to reflect the definitions and standards under U.S. disclosure requirements, that the Talisman reserves evaluation and approvals processes are of a high quality and that the guidance is consistent with good industry practice. Talisman also conducts periodic internal audits of the procedures, records and controls relating to the preparation of reserves data.

Accordingly, Talisman considers the reliability of its internally generated reserves data to be not materially less than would be afforded by the independent evaluator requirements of NI 51-101.

The following table sets forth Talisman's estimates of its proved developed, proved undeveloped, total proved, probable and total proved plus probable reserves as at December 31, 2003.

	Proved Developed ²		Proved Undeveloped ³		Total Proved ¹		Total Probable ⁴		Total Proved and Probable	
	Gross ⁵	Net ⁶	Gross ⁵	Net ⁶	Gross ⁵	Net ⁶	Gross ⁵	Net ⁶	Gross ⁵	Net ⁶
Oil and Natural Gas Liquids										
(millions of barrels)										
North America										
Canada	186.4	155.4	3.8	3.0	190.2	158.4	86.8	72.8	277.0	231.2
United States	—	—	—	—	—	—	—	—	—	—
North Sea⁷	213.0	211.8	43.4	43.2	256.4	255.0	172.3	171.8	428.7	426.8
Southeast Asia										
Indonesia ⁸	18.2	11.6	0.1	0.1	18.3	11.7	15.6	9.9	33.9	21.6
Malaysia/Vietnam ⁸	11.3	7.0	54.8	33.8	66.1	40.8	47.7	29.5	113.8	70.3
Algeria⁸	25.5	14.6	3.5	2.0	29.0	16.6	40.2	23.0	69.2	39.6
Trinidad⁸	—	—	19.2	18.1	19.2	18.1	19.3	18.2	38.5	36.3
Total	454.4	400.4	124.8	100.2	579.2	500.6	381.9	325.2	961.1	825.8
Natural Gas										
(billions of cubic feet)										
North America										
Canada	2,321.1	1,818.7	214.7	167.7	2,535.8	1,986.4	1,309.6	1,023.6	3,845.4	3,010.0
United States	82.9	71.7	26.2	22.6	109.1	94.3	50.0	43.3	159.1	137.6
North Sea⁷	220.1	200.7	35.0	34.9	255.1	235.6	134.6	131.7	389.7	367.3
Southeast Asia										
Indonesia ⁸	821.4	533.3	232.8	151.2	1,054.2	684.5	1,088.0	706.5	2,142.2	1,391.0
Malaysia/Vietnam ⁸	99.5	60.6	418.3	241.6	517.8	302.2	232.2	135.2	750.0	437.4
Algeria⁸	—	—	—	—	—	—	—	—	—	—
Trinidad⁸	—	—	223.5	211.0	223.5	211.0	131.9	124.5	355.4	335.5
Total	3,545.0	2,685.0	1,150.5	829.0	4,695.5	3,514.0	2,946.3	2,164.8	7,641.8	5,678.8
Synthetic Oil⁹										
(millions of barrels)										
Canada	42.3	35.8	—	—	42.3	35.8	23.9	20.2	66.2	56.0

Notes:

- 1 "Proved" reserves have been estimated in accordance with the SEC definition set out in Rule 4-10(a) of Regulation S-X under the Securities Exchange Act of 1934 as follows: Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.
- 2 "Proved Developed" reserves are those reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.
- 3 "Proved Undeveloped" reserves are those reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells for which a relatively major expenditure is required for recompletion. Inclusion of reserves on undrilled acreage is limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are included only if it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.
- 4 "Probable" reserves are less certain than proved reserves and have been estimated in accordance with the definition set out by the Society of Petroleum Engineers and the World Petroleum Congress ("SPE/WPC"). That is, probable reserves are those unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable. Probable reserves are estimated under the same existing economic and operating conditions used for proved reserves.
- 5 "Gross" reserves are the remaining reserves of Talisman before deduction of royalties.
- 6 "Net" reserves are the remaining reserves of Talisman after deduction of royalties.
- 7 "North Sea" includes the United Kingdom, Norway and the Netherlands Continental Shelf.
- 8 Interests of various governments, other than working interests or income taxes, are accounted for as royalties. Royalties are reflected in "net" reserves using effective rates over the life of the contract.
- 9 Talisman has not independently estimated synthetic oil reserves volumes. Reserves volumes reported herein are consistent with reserves estimates published by the general partner of the limited partnership through which Talisman has an indirect 1.25% interest in the Syncrude project.

A report on reserves data by Talisman's IQRE and a report of management and directors on oil and gas disclosure are provided in Schedules A and B, respectively, to this Annual Information Form. The Company does not file estimates of its total oil and gas reserves with any U.S. agency or federal authority other than the SEC.

Additional Information

Additional information relating to Talisman's reserves and oil and gas activities is contained under the heading "Supplementary Information" on pages 72 to 75, and under the heading "Continuity of Proved Gross Reserves" on page 83 of the Annual Report, which information is incorporated herein by reference.

Product netback information, including annual average sales prices and costs, is included in the Annual Report on page 78 and page 81, which information is incorporated herein by reference.

Future commitments to buy, sell, exchange, process and transport oil or gas of the Company are described under note 10 entitled "Contingencies and Commitments" in the audited consolidated financial statements of the Company for the year ended December 31, 2003, which information is incorporated herein by reference.

Risks and Uncertainties

Information with respect to the risks and uncertainties affecting Talisman's business is described in "Management's Discussion and Analysis" under the heading "Risks and Uncertainties", which information is incorporated herein by reference.

Competitive Conditions

The oil and gas industry, both within Canada and internationally, is highly competitive in all aspects of the business, including the acquisition of properties, the exploration for and development of new sources of supply and the marketing of current production. With respect to the exploration, development and marketing of oil and natural gas, the Company's competitors include major integrated oil and gas companies, numerous other independent oil and gas companies, individual producers and operators and national oil companies. A number of the Company's competitors have financial and other resources substantially in excess of those available to the Company. In addition, oil and gas producers in general compete indirectly against others engaged in supplying alternative forms of energy, fuel and related products to consumers.

Environmental Protection

The oil and gas industry is subject to safety and environmental regulation pursuant to extensive legislation, enacted by various levels of government, both in Canada and internationally. The Company maintains a comprehensive range of internal programs and controls to promote regulatory compliance and an appropriate level of safety and environmental protection across its operations. Public expectation regarding the industry's safety and environmental performance remains high and this continues to translate into new and generally more rigorous policies, legislation and regulations. Within jurisdictions and sectors, these regulatory instruments apply generally and do not typically influence competitive position.

The Company does not anticipate making extraordinary material expenditures for environmental compliance during 2004. However, it does expect to incur site restoration costs over a prolonged period as existing fields become fully produced. Talisman provides for future abandonment and reclamation costs in its financial statements in accordance with Canadian generally accepted accounting principles. Additional information regarding future abandonment and reclamation costs is set forth under note 10 entitled "Contingencies and Commitments" in the audited consolidated financial statements of the Company for the year ended December 31, 2003, which information is incorporated herein by reference.

Employees

At December 31, 2003, Talisman's permanent staff complement¹ was 1,758, as set forth in the table below.

	Permanent staff complement ¹ as at December 31, 2003
North America	1,312
North Sea	273
Southeast Asia	168
Algeria	1
Other ²	4
Total	1,758

Notes:

1 Contractors and temporary staff are not included in complement numbers.

2 "Other" includes Qatar, Trinidad and employees seconded to BHP Billiton Petroleum (Americas) Inc.

SELECTED CONSOLIDATED FINANCIAL INFORMATION

Annual Information

The following table sets out selected financial information of the Company for the past three years.

Years ended December 31
(millions of Canadian dollars unless otherwise stated)

	2003	2002	2001
Balance Sheet			
Current assets	975	917	799
Other assets	612	635	559
Property, plant and equipment	9,778	10,042	9,461
Total assets	11,365	11,594	10,819
Current liabilities	1,218	989	1,204
Deferred credits and other liabilities	2,985	3,106	2,695
Long-term debt	2,203	2,997	2,794
Shareholders' equity	4,959	4,502	4,126
Total liabilities and shareholders' equity	11,365	11,594	10,819
Results of operations			
Revenue	4,477	4,452	4,140
Expenses	3,496	3,384	2,844
Gain on sale of Sudan operations	296	—	—
Income before taxes	1,277	1,068	1,296
Taxes	270	544	563
Net Income	1,007	524	733
Preferred security charges, net of tax	22	24	24
Net income available to common shareholders	985	500	709
Capital Expenditures	2,986	2,150	2,213
Proceeds on disposition	(100)	(72)	(162)
Net capital expenditures	2,886	2,078	2,051
Per common share (dollars)			
Net income	7.65	3.73	5.25
Diluted net income	7.57	3.67	5.16
Dividends per share	0.70	0.60	0.60

The above financial data has been taken from the audited consolidated financial statements of the Company for the years ended December 31, 2003, 2002 and 2001. The audited consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles.

As disclosed in note 1(o) to the December 31, 2003 audited consolidated financial statements of the Company, the amortization of good will ceased effective January 1, 2003.

As disclosed in note 17 to the December 31, 2003 audited consolidated financial statements of the Company and in the Company's Management's Discussion and Analysis, Talisman completed the sale of its indirect interest in the Greater Nile Oil Project in Sudan to ONGC Videsh Limited, a subsidiary of India's national oil company on March 12, 2003.

Dividends

In 2003, the Company paid semi-annual dividends on Talisman common shares. The dividend paid in June was \$0.30 per share. The dividend amount was increased to \$0.40 per share for the December payment. The Company's dividend policy is subject to semi-annual review by the Board of Directors.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Reference is made to the "Management's Discussion and Analysis" that accompanies the audited consolidated financial statements of the Company for the year ended December 31, 2003, which information is incorporated herein by reference.

MARKET FOR THE SECURITIES OF THE COMPANY

The common shares of the Company are listed on the Toronto and New York stock exchanges under the trading symbol TLM. The Company's 8.9% Preferred Securities are listed on the New York Stock Exchange under the trading symbol TLM PrB. The Company's Pound Sterling 250,000,000 6.625% Notes are listed on the London Stock Exchange.

DIRECTORS AND OFFICERS

Information is given below with respect to each of the current directors and officers of the Company. The term of office of each director expires at the end of the 2004 Annual Meeting.

Directors

The following table sets out the name, municipality of residence, year first elected to the Board and principal occupation within the past five years or more of each of the directors of the Company.

Name and Municipality of Residence	Year First Became Director	Principal Occupation
Douglas D. Baldwin ^{2, 3, 4, 6} Calgary, Alberta	2001	Chairman of the Board of the Company; director of various corporations; from 1999 to 2001, President and Chief Executive Officer of TransCanada PipeLines Limited (pipeline and power company); from 1992 to 1998, Senior Vice-President and Director of Imperial Oil Limited (natural resource company); from 1988 to 1992, President and Chief Executive Officer, Esso Resources Canada Limited (natural resource company).
James W. Buckee ² Calgary, Alberta	1992	President and Chief Executive Officer of Talisman Energy Inc.; prior to May 1993, President and Chief Operating Officer of the Company; prior to August 1991, Manager, Planning of BP Exploration Company Ltd. (natural resource company).
Kevin S. Dunne ^{3, 5, 6} London, United Kingdom	2003	Director of the Company; until March 2003, director of Talisman Energy Sweden AB (a wholly owned subsidiary of the Company); until 2001, held various international senior and executive management positions with BP plc (international integrated oil and gas company) including General Manager, Abu Dhabi Company for Onshore Oil Operations (ADCO), a BP joint venture; 1991 to 1994, Corporate Associate President, BP Indonesia; and 1990 to 1991, Corporate Head of Strategy for the BP Group based in London.
Al L. Flood, C.M. ^{1, 4} Thornhill, Ontario	2000	Director of various corporations; from June 1999 to March 2000, Chairman of the Executive Committee of Canadian Imperial Bank of Commerce ("CIBC") (a Canadian chartered bank); prior to June 1999, Chairman and Chief Executive Officer of CIBC and held various positions in the domestic and international operations of CIBC.

Name and Municipality of Residence	Year First Became Director	Principal Occupation
Dale G. Parker ^{1, 5} Vancouver, British Columbia	1993	Director of various corporations and public administration and financial institution advisor; prior to January 1998, President and Chief Executive Officer of Workers' Compensation Board of British Columbia; prior to November 1994, President of White Spot Limited (food services company) and Executive Vice-President of Shato Holdings Ltd. (food processing and services and real estate company); prior to November 1993, Executive Vice-President and Chief Financial Officer of Shato Holdings Ltd.; prior to November 1992, Chairman and Chief Executive Officer of British Columbia Financial Institutions Commission (regulator of financial institutions).
Roland Priddle ^{3, 5} Victoria, British Columbia	2000	Consultant to public and private sector entities on policy and regulatory issues in oil and gas; prior to 1998, Chairman, National Energy Board of Canada.
Lawrence G. Tapp ^{3, 4} Langley, British Columbia	2001	Chairman of Tapp Technologies Inc. (wine label production company); director of various corporations; from 1995 to 2003, Dean of the Richard Ivey School of Business of the University of Western Ontario; from 1992 to 1995, Executive in Residence of the Faculty of Management and Adjunct Professor, University of Toronto; from 1985 to 1992, Vice Chairman, President and Chief Executive Officer of Lawson Mardon Group Limited (packaging conglomerate).
Stella M. Thompson ^{4, 5} Calgary, Alberta	1995	Principal of Governance West Inc. (corporate governance consulting company); President of Stellar Energy Ltd. (energy and management consulting company); director of various corporations; prior to June 1991, Vice-President, Planning, Business Information & Systems of Petro-Canada Products (petroleum refining and marketing company).
Robert G. Welty ^{1, 2} Calgary, Alberta	2003	Director and Chief Executive Officer of Sterling Resources Ltd. (oil and gas exploration and development company) since 1998; 1996 to 1997, President, Escondido Resources (International) Ltd. (oil and gas exploration company); 1994 to 1995, President and Chief Executive Officer of Canadian Fracmaster Ltd. (oil field service company); 1992 to 1994, President and Chief Executive Officer of Bow Valley Energy Inc. (oil and gas exploration and development company); 1976 to 1988, President and Chief Executive Officer of Asamera Inc. (oil and gas exploration and development company).
Charles W. Wilson ^{1, 2, 6} Evergreen, Colorado	2002	Director of various corporations; from 1993 to 1999, President and Chief Executive Officer of Shell Canada (integrated oil and gas company); from 1988 to 1993, Executive Vice President US Downstream Oil and Chemical of Shell Oil US (integrated oil and gas company); prior to 1988, Vice President US Refining and Marketing of Shell Oil US and held various positions in the domestic and international natural resource operations of Shell.

Notes:

1 Member of the Audit Committee.

2 Member of the Executive Committee.

3 Member of the Governance and Nominating Committee.

4 Member of the Management Succession and Compensation Committee.

5 Member of the Pension Funds Committee.

6 Member of the Reserves Committee.

Mr. Parker was a director of Royal Oak Mines Inc., a publicly traded North American gold mining corporation, and he was a director of Agro Pacific Industries Ltd., a publicly traded agricultural corporation, when each corporation instituted proceedings under the *Companies' Creditors Arrangement Act* (Canada). Ms. Thompson was a director of Laidlaw Inc., a public holding company, when it obtained an order in the United States Bankruptcy Court for the Western District of New York confirming its plan of reorganization and an order from the Ontario Superior Court of Justice under the *Companies' Creditors Arrangement Act* (Canada) recognizing and implementing the plan in Canada. In 2003, a small, private technology company, for which Michael McDonald an officer of the Company served as a director, declared bankruptcy.

Officers

The following table sets out the name, municipality of residence and office held with Talisman of each of the executive officers and Assistant Corporate Secretaries of the Company.

Name and Municipality of Residence	Office
James W. Buckee Calgary, Alberta	President and Chief Executive Officer
Ronald J. Eckhardt Calgary, Alberta	Executive Vice-President, North American Operations
T. Nigel D. Hares Calgary, Alberta	Executive Vice-President, Frontier and International Operations
Joseph E. Horler Calgary, Alberta	Executive Vice-President, Marketing
Michael D. McDonald Calgary, Alberta	Executive Vice-President, Finance and Chief Financial Officer
Robert M. Redgate Calgary, Alberta	Executive Vice-President, Corporate Services
M. Jacqueline Sheppard Calgary, Alberta	Executive Vice-President, Corporate and Legal, and Corporate Secretary
John 't Hart Calgary, Alberta	Executive Vice-President, Exploration
Christine D. Lee Calgary, Alberta	Assistant Corporate Secretary
Ardith D. Wagner Calgary, Alberta	Assistant Corporate Secretary

In early 2003, the Company changed the titles of all its vice-presidents to better reflect the roles and responsibilities of their continuing offices. Mr. McDonald has held his current position since March 12, 2001. Prior to that date, he served as Vice-President, Business Development of the Company. Dr. 't Hart has held his current position since June 25, 2003. Prior to that, he served as Senior Manager, International Exploration of the Company since April 1, 2003 and prior to that, he served as Manager, International Exploration of the Company. Mr. Eckhardt has held his current position since October 1, 2003. Prior to that, he served as Vice-President, Southern District of North American Operations of the Company since January 23, 2003, and prior to that he served as Senior Manager, Western Operations and prior to that as Manager, Eastern Operations of the Company. All of the other executive officers of the Company have held their offices for at least five years.

Shareholdings of Directors and Officers

As of the date hereof, the directors and executive officers of the Company, as a group, beneficially own, directly or indirectly, or exercise control or direction over 119,927 common shares of the Company, representing 0.0937% of the issued and outstanding common shares of the Company.

ADDITIONAL INFORMATION

The Company will provide to any person or company upon request to the Assistant Corporate Secretary of the Company:

- (a) when the securities of the Company are in the course of a distribution pursuant to a preliminary short form prospectus or a short form prospectus:
 - (i) one copy of this Annual Information Form, together with one copy of any document, or the pertinent pages of any document, incorporated herein by reference;
 - (ii) one copy of the audited consolidated financial statements of the Company, together with the report of the auditor thereon, for the Company's most recently completed financial year in respect of which such financial statements have been filed and one copy of any interim financial statements of the Company which have been filed subsequent to the annual financial statements;
 - (iii) one copy of the Management Proxy Circular of the Company in respect of its most recent annual meeting of shareholders, which involved the election of directors;
 - (iv) one copy of any other document or report which is incorporated by reference into the preliminary short form prospectus or the short form prospectus and is not required to be provided under (i) to (iii) above; or
- (b) at any other time, one copy of any other document referred to in paragraphs (a)(i), (ii) and (iii) above, provided that the Company may require the payment of a reasonable charge, if the person or company requesting a document is not a security holder of the Company.

Additional information including directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and options to purchase securities is contained in the Company's Management Proxy Circular. Additional financial information is provided in the Company's audited consolidated financial statements for the year ended December 31, 2003.

Copies of the Company's Annual Report may be obtained from Talisman's website at www.talisman-energy.com or upon request from:

Investor Relations and Corporate Communications Department

Talisman Energy Inc.

Suite 3400, 888 Third Street S.W.

Calgary, Alberta T2P 5C5

E-Mail: tlm@talisman-energy.com

SCHEDULE A

REPORT ON RESERVES DATA BY TALISMAN'S INTERNAL QUALIFIED RESERVES EVALUATOR

To the Board of Directors of Talisman Energy Inc. (the "Company"):

1. The Company's staff and I have evaluated the Company's reserves data as at December 31, 2003. The reserves data, which has been prepared in accordance with U.S. disclosure requirements, including the relevant definitions, legal requirements and standards of the United States Securities and Exchange Commission and the United States Financial Accounting Standards Board ("U.S. Disclosure Requirements"), consist of the following:
 - (a) proved oil and gas reserves quantities estimated as at December 31, 2003; and
 - (b) the related standardized measure of discounted future net cash flows.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society) applied in such modified manner as we considered necessary to reflect the terminology and standards of the U.S. Disclosure Requirements. We are not independent of the Company, within the meaning of the term "independent" under those standards.
4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook as modified as set out above.
5. The following sets forth the standardized measure of discounted future net cash flows (after deducting income taxes) attributed to proved oil and gas reserve quantities, calculated using a discount rate of 10%, included in the reserves data of the Company evaluated for the year ended December 31, 2003:

Location of Reserves (country or foreign geographic area)	Standardized Measure of Discounted Future Net Cash Flows (millions of Canadian dollars, after income taxes, 10% discount rate)
Canada	\$ 4,173
United States	\$ 419
North Sea	\$ 1,817
Southeast Asia	\$ 1,407
Algeria	\$ 273
Trinidad	\$ 147
	\$ 8,236

6. In our opinion, the reserves data evaluated by us have, in all material respects, been determined in accordance with the COGE Handbook applied in the modified manner as set out above.
7. We have no responsibility to update our evaluation for events and circumstances occurring after the date of this report.
8. Reserves data are estimates only and not exact quantities. In addition, the reserves data are based on judgements regarding future events. Accordingly, actual results will vary and the variations may be material.

(Signed)

Michael Adams
Internal Qualified Reserves Evaluator
Talisman Energy Inc.
Calgary, Alberta
March 3, 2004

SCHEDULE B

REPORT ON MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Talisman Energy Inc. (the "Company") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data prepared in accordance with U.S. disclosure requirements, including the relevant definitions, legal requirements and standards of the United States Securities and Exchange Commission and the United States Financial Accounting Standards Board ("U.S. Disclosure Requirements"), which consist of the following:

- (a) proved oil and gas reserve quantities estimated as at December 31, 2003; and
- (b) the related standardized measure of discounted future net cash flows.

The Company's reserves evaluation staff, including our Internal Qualified Reserves Evaluator who is an employee of the Company, have evaluated the Company's reserves data. The report of the Internal Qualified Reserves Evaluator accompanies this report.

The Reserves Committee of the Board of Directors has:

- (a) reviewed the Company's procedures for providing information to the Internal Qualified Reserves Evaluator;
- (b) met with the Internal Qualified Reserves Evaluator to determine whether any restrictions placed by management affect the ability of the Internal Qualified Reserves Evaluator to report without reservation; and
- (c) reviewed the reserves data with management and the Internal Qualified Reserves Evaluator.

The Reserves Committee of the Board of Directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved:

- (a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information contained in the Annual Information Form accompanying this report;
- (b) the filing of the report of the Internal Qualified Reserves Evaluator on the reserves data; and
- (c) the content and filing of this report.

In our view, the reliability of the internally generated reserves data is not materially less than would be afforded by our involving independent qualified reserves evaluators or independent qualified reserves auditors to evaluate or audit and review the reserves data. The Company is therefore relying on an exemption, which it sought and was granted by securities regulatory authorities, from the requirement under securities legislation to involve independent qualified reserves evaluators or independent qualified reserves auditors.

The primary factors supporting the involvement of independent qualified reserves evaluators or independent qualified reserves auditors apply when (i) their knowledge of, and experience with, a reporting issuer's reserves data are superior to that of the internal evaluators and (ii) the work of the independent qualified reserves evaluators or independent qualified reserves auditors is significantly less likely to be adversely influenced by self-interest or management of the reporting issuer than the work of internal reserves evaluation staff. In our view, neither of these factors applies in our circumstances.

Our view is based in large part on the following. Our reserves data were developed in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook applied in such modified manner as the Company considered necessary to reflect the terminology and standards of the U.S. Disclosure Requirements. Our procedures, records and controls relating to the accumulation of source data and preparation of reserves data by our internal reserves evaluation staff have been established, refined and documented over many years. Our internal reserves evaluation staff includes approximately 90 persons with full-time or part-time responsibility for reserves evaluation with an average of approximately 15 full-time or part-time years of relevant experience in evaluating reserves, of whom 52 are qualified reserves evaluators for purposes of securities regulatory requirements. Our internal reserves evaluation management personnel includes approximately 24 persons with full-time or part-time responsibility for reserves evaluation management with an average of approximately 21 full-time or part-time years of relevant experience in evaluating and managing the evaluation of reserves, 14 of whom were qualified reserves evaluators for purposes of securities regulatory requirements.

Reserves data are estimates only, and are not exact quantities. In addition, the reserves data are based on judgements regarding future events. Accordingly, actual results will vary and the variations may be material.

(Signed)

James W. Buckee

President and Chief Executive Officer

(Signed)

T. Nigel D. Hares

Executive Vice-President,

Frontier and International Operations

(Signed)

Ronald J. Eckhardt

Executive Vice-President,

North American Operations

(Signed)

Charles W. Wilson

Director

(Signed)

Kevin S. Dunne

Director

March 3, 2004



**NOTICE OF ANNUAL AND SPECIAL MEETING OF SHAREHOLDERS
MANAGEMENT PROXY CIRCULAR**

MAY 4, 2004

TALISMAN

E N E R G Y

NOTICE OF ANNUAL AND SPECIAL MEETING OF SHAREHOLDERS

May 4, 2004

NOTICE IS HEREBY GIVEN that the Annual and Special Meeting of the Shareholders (the "Meeting") of TALISMAN ENERGY INC. (the "Company") will be held in the Exhibition Hall, North Building of the Telus Convention Centre, 136 Eighth Avenue S.E., Calgary, Alberta, Canada, on Tuesday, May 4, 2004 at 10:30 a.m. (local time) for the following purposes:

1. to receive the annual report and the consolidated financial statements of the Company for the year ended December 31, 2003 together with the report of the auditor thereon;
2. to elect the directors for the ensuing year;
3. to appoint the auditor for the ensuing year;
4. to consider, and if thought appropriate, to pass, with or without variation, a special resolution to amend the Articles to effect a three for one division of the Company's Common Shares, as described in the Company's Management Proxy Circular accompanying this Notice of Meeting; and
5. to transact such further and other business as may properly come before the Meeting or any adjournment thereof.

Registered holders of Common Shares unable to attend the Meeting in person are requested to complete the enclosed form of proxy and return it in the envelope provided to the Company's Transfer Agent and Registrar, Computershare Trust Company of Canada, 100 University Avenue, Toronto, Ontario, M5J 2Y1 no later than 10:30 a.m. (local time, Toronto, Ontario) May 3, 2004, or one business day preceding any adjournment of the Meeting. Alternatively, telephone and Internet voting options are available. Please see the form of proxy for more details. Non-registered shareholders are advised to refer to the Company's Management Proxy Circular and to the voting instruction form for instructions relevant to them.

Only registered holders of Common Shares of the Company at the close of business on March 18, 2004, or their duly appointed proxyholders will be entitled to vote at the Meeting.

DATED at Calgary, Alberta this 3rd day of March, 2004.

BY ORDER OF THE BOARD



M. Jacqueline Sheppard
Corporate Secretary

Full instructions explaining the process for a shareholder to attend the Meeting in person are set out in the Management Proxy Circular accompanying this Notice of Meeting. Shareholders who have questions may call Valiant Trust Company toll-free at 1-866-313-1872 for further information.

MANAGEMENT PROXY CIRCULAR

GENERAL PROXY INFORMATION

This management proxy circular (the "Circular") is furnished in connection with the solicitation of proxies by or on behalf of the management of TALISMAN ENERGY INC. (the "Company") for use at the Annual and Special Meeting of Shareholders of the Company (the "Meeting") to be held in the Exhibition Hall, North Building of the Telus Convention Centre, 136 Eighth Avenue S.E., Calgary, Alberta, Canada, on Tuesday, May 4, 2004 at 10:30 a.m. (local time) and at any adjournment thereof, for the purposes set forth in the attached Notice of Meeting. Please read this Circular to obtain information about how shareholders may participate at the Meeting either in person or through the use of proxies.

Solicitation of Proxies

Proxies in the enclosed form are solicited by or on behalf of the management of the Company. Solicitation of proxies will be primarily by mail, but employees of the Company may also solicit proxies by telephone. Brokers, nominees or other persons holding shares of the Company in their names for others will be reimbursed for their reasonable charges and expenses in forwarding proxies and proxy material to non-registered shareholders. The Company has also retained an independent proxy solicitation agent, Valiant Trust Company, to assist in the solicitation of proxies for the Meeting, at a cost not to exceed \$20,000. The Company will bear the cost of all proxy solicitations on behalf of management of the Company.

Registered and Non-Registered Shareholders

Shareholders of the Company are either registered or non-registered. Only a relatively small number of shareholders are registered. Registered shareholders hold shares of the Company ("Common Shares") in their own names because they specifically requested that their names be registered on the records of the Company or purchased their Common Shares directly from the Company and not through an intermediary. (Intermediaries include, among others, banks, trust companies, securities dealers or brokers.) Most shareholders are non-registered because their Common Shares are registered in the name of either (a) an intermediary with whom the non-registered shareholder deals in respect of the Common Shares, or (b) a clearing agency (such as The Canadian Depository for Securities Limited) of which the intermediary is a participant.

Only registered shareholders or duly appointed proxyholders will be permitted to attend and vote at the Meeting. Non-registered shareholders may vote through a proxy or attend the Meeting to vote their own shares only if, before the Meeting, they communicate instructions to the intermediary or clearing agency that holds their Common Shares. Instructions for voting through a proxy, appointing a proxyholder and attending the Meeting to vote are set out in this Circular. Shareholders who have questions may call Valiant Trust Company toll-free at 1-866-313-1872 for further information.

A shareholder may receive multiple packages of Meeting materials if the shareholder holds Common Shares through more than one intermediary, or if the shareholder is both a registered shareholder and a non-registered shareholder for different shareholdings. Any such shareholder should repeat the steps to vote through a proxy, appoint a proxyholder or attend the Meeting, if desired, separately for each shareholding to ensure that all the shares from the various shareholdings are represented and voted at the Meeting.

Voting through a Proxy

Shareholders who are unable to be present at the Meeting may vote through the use of proxies. Shareholders should convey their voting instructions using one of the three voting methods available: (i) use of the voting instruction form or form of proxy to be returned by mail or delivery, (ii) use of the telephone voting procedure, or (iii) use of the Internet voting procedure. By conveying your voting instructions in one of the three ways, you can participate in the Meeting through the person or persons named on the voting instruction form or form of proxy.

If you do not indicate a voting preference for an item of business presented, your Common Shares will be voted FOR the election of directors named in this Circular, FOR the appointment of auditor and FOR the amendment of Articles to effect a three for one division of the Common Shares, all as more particularly described under the relevant sections of this Circular.

To convey voting instructions through any of the three methods available, a shareholder must locate the voting instruction form or form of proxy, one of which is included with the Circular in the package of Meeting materials sent to all shareholders. The voting instruction form is a white, computer scanable document with red squares marked "X". It is sent to most non-registered shareholders. The form of proxy is a yellow form headed "Form of Proxy". It is sent to all registered shareholders and a small number of non-registered shareholders.

Mail

A shareholder who elects to use the paper voting procedure should complete and return either a yellow form of proxy or a voting instruction form, one of which is included in each package of Meeting materials.

Yellow form of proxy

If your yellow form of proxy contains a self-adhesive label containing a bar code and other information, follow the instructions to affix the label to the yellow form of proxy. If the yellow form of proxy is already signed, do not sign it again. Complete the remainder of the yellow form of proxy. Ensure that you date and sign the form at the bottom. Return your completed yellow form of proxy, in the envelope provided, to the Company's Transfer Agent and Registrar, Computershare Trust Company of Canada ("Computershare"), 100 University Avenue, Toronto, Ontario M5J 2Y1 no later than 10:30 a.m. (local time, Toronto, Ontario) May 3, 2004 or one business day preceding any adjournment of the Meeting.

Voting instruction form

Complete the voting instruction form. Ensure that you date and sign the form at the bottom. Return the voting instruction form to the relevant intermediary in the envelope provided by April 30, 2004 or the cut-off date shown on the voting instruction form.

Telephone or Internet

Shareholders may convey their voting instructions using a touch-tone telephone or the Internet. The relevant toll-free telephone number or website address is set out on the voting instruction form or yellow form of proxy. Follow the instructions given over the telephone or through the Internet to cast your vote. When instructed to enter a control number or holder account number and proxy access number, consult your voting instruction form or your yellow form of proxy. Votes conveyed by telephone or the Internet must be received no later than the cut-off time given on the voting instruction form or the yellow form of proxy.

Appointing a Proxyholder

Shareholders unable to attend the Meeting in person may participate and vote at the Meeting through a proxyholder. The persons named as proxyholders to represent shareholders at the Meeting, D. D. Baldwin and J.W. Buckee, are directors or officers of the Company. **A shareholder has the right to appoint a person other than those named to represent such shareholder at the Meeting. A non-registered shareholder who would like to attend the Meeting to vote must appoint himself or herself proxyholder.** To appoint a person other than D. D. Baldwin or J.W. Buckee proxyholder, strike out the names of D. D. Baldwin and J.W. Buckee on the voting instruction form or yellow form of proxy and write the name of the person you would like to appoint as your proxyholder in the blank space provided. You should notify any person you appoint as your proxyholder. That person need not be a shareholder of the Company.

Non-registered shareholders appointing a proxyholder using a voting instruction form should fill in the rest of the form indicating a vote "for", "against", or "withhold", as the case may be, for each of the proposals listed, sign and date the form and return it to the relevant intermediary or clearing agency in the envelope provided by April 30, 2004 or the cut-off time given on the form. **No person will be admitted at the Meeting to vote by presenting a voting instruction form.**

Shareholders appointing a proxyholder using a yellow form of proxy are encouraged to return the completed and signed form to Computershare Trust Company of Canada, 100 University Avenue, Toronto, Ontario M5J 2Y1, in the envelope provided by 10:30 a.m. (local time, Toronto, Ontario) May 3, 2004 or one business day preceding any adjournment of the Meeting; however, proxyholders named on a signed yellow form of proxy will be admitted at the Meeting to vote upon presentation of the yellow form of proxy.

Alternatively, any shareholder may use the Internet to appoint a proxyholder. To use this option, access the website address printed on the voting instruction form or yellow form of proxy and follow the instructions set out on the website. Refer to the control number or holder account number and proxy access number printed on the voting instruction form or yellow form of proxy when required to enter these numbers.

Attending the Meeting to Vote

Only registered shareholders or duly appointed proxyholders will be permitted to attend and vote at the Meeting. Non-registered shareholders will not be permitted to attend the Meeting to vote by presenting their voting instruction forms at the door. In order for non-registered shareholders to attend the Meeting to vote, they must carefully follow the instructions provided under the heading "Appointing a Proxyholder" in this Circular to appoint themselves proxyholders before the Meeting in order to be admitted at the Meeting to vote.

Shareholders who have questions may call Valiant Trust Company toll-free at 1-866-313-1872 for further information.

Discretionary Authority of Proxyholder

The enclosed voting instruction form or yellow form of proxy confers discretionary authority on the proxyholder in respect of amendments or variations to matters identified in the Notice of Meeting and other matters that may properly come before the Meeting or any adjournment thereof. As of the date of this Circular, the management of the Company is not aware of any such amendments, variations or other matters to be presented at the Meeting other than those identified in the Notice of Meeting; however, if any such matter is presented, the proxy will be voted in accordance with the best judgment of the proxyholder named in the form. Where a shareholder has not specifically appointed a person as proxyholder, a management nominee will be the proxyholder, and the proxy will be voted in accordance with the best judgment of the management nominee.

Revocation of Voting Instructions or Proxies

Shareholders may revoke their voting instructions or proxies as follows.

Voting instructions submitted by mail, telephone or through the Internet using a voting instruction form will be revoked if the relevant intermediary receives new voting instructions before the close of business on April 30, 2004, or two business days before any adjournment of the Meeting. After such time, non-registered shareholders should call Valiant Trust Company toll-free at 1-866-313-1872 for help to revoke voting instructions.

Proxies submitted by mail, telephone or through the Internet using a yellow form of proxy may be revoked by submitting a new proxy to Computershare before 10:30 a.m. (local time, Toronto, Ontario) May 3, 2004, or one business day before any adjournment of the Meeting. Alternatively, a shareholder who wishes to revoke a proxy may do so by depositing an instrument in writing addressed to the attention of the Corporate Secretary and executed by the shareholder or by the shareholder's attorney authorized in writing. Such an instrument must be deposited at the registered office of the Company, located at Suite 3400, 888 Third Street S.W., Calgary, Alberta, T2P 5C5, at any time up to and including the last business day preceding the day of the Meeting, or any adjournment thereof, at which the proxy is to be used. On the day of the Meeting or any adjournment thereof, a shareholder may revoke a proxy by depositing such an instrument in writing with the Chairman of the Meeting; however, it will not be effective with respect to any matter on which a vote has already been cast.

In addition, a proxy may be revoked by any other manner permitted by law.

Voting Shares and Principal Holders Thereof

There were 128,032,077.6 Common Shares of the Company outstanding at March 3, 2004. Each Common Share is entitled to one vote on all matters to be voted upon at the Meeting.

To the knowledge of the directors or officers of the Company, there is no single shareholder who beneficially owns, directly or indirectly, or exercises control or direction over Common Shares carrying more than 10% of the voting rights attached to the Common Shares. Each of The Canadian Depository for Securities Limited and CEDE & Co. hold in excess of 10% of the Common Shares for the benefit of their respective participants.

Record Date

Only registered shareholders at the close of business on March 18, 2004 will be entitled to vote in respect of the matters to be voted upon at the Meeting, or any adjournment thereof.

BUSINESS OF THE MEETING

Election of Directors

The Board of Directors is elected annually and consists of such number as fixed from time to time by resolution of the directors, such number being not less than five and not more than 20. The number of directors to be elected at the Meeting is currently fixed at nine. Each elected director will hold office until the next annual meeting or until his or her successor is duly elected or appointed.

Management of the Company proposes to nominate for election as directors at the Meeting the persons listed in the following table. All proposed nominees have consented to be named in this Circular and to serve as directors if elected. Management has no reason to believe that any of the nominees will be unable to serve as directors but, should any nominee become unable to do so for any reason prior to the Meeting, the persons named in the enclosed voting instruction form or form of proxy, unless directed to withhold from voting, reserve the right to vote for other nominees at their discretion. To be effective, the resolution electing directors must be passed by a majority of the votes cast thereon by the shareholders at the Meeting.

Roland Priddle, who has been a director of the Company since 2000, and who has now reached the Company's mandatory retirement age, will not be standing for re-election to the Board at the Meeting.

The following table sets forth information with respect to each of the nominees for election as a director, including all officer positions currently held with the Company and principal occupation or employment for the past five years or more. Each of the nominees has served as a director of the Company since the year he or she first became a director.

The Board of Directors has the following committees: the Audit Committee, the Executive Committee, the Governance and Nominating Committee, the Management Succession and Compensation Committee, the Pension Funds Committee and the Reserves Committee. For a description of the committees of the Board of Directors, see the Statement of Corporate Governance Practices set out in Schedule A to this Circular. Membership on the Board committees is also noted in the table below.

Name and Municipality of Residence	Year First Became Director of the Company	Present Principal Occupation or Employment (including all officer positions currently held with the Company) and Principal Occupation or Employment for the Past Five Years or More
Douglas D. Baldwin ^{2, 3, 4, 6} Calgary, Alberta	2001	Chairman of the Board of the Company; director of various corporations; from 1999 to 2001, President and Chief Executive Officer ("CEO") of TransCanada PipeLines Limited (pipeline and power company); from 1992 to 1998, Senior Vice-President and Director of Imperial Oil Limited (natural resource company); from 1988 to 1992, President and Chief Executive Officer, Esso Resources Canada Limited (natural resource company).
James W. Buckee ² Calgary, Alberta	1992	President and Chief Executive Officer of Talisman Energy Inc.; prior to May 1993, President and Chief Operating Officer of the Company; prior to August 1991, Manager, Planning of BP Exploration Company Ltd. (natural resource company).
Kevin S. Dunne ^{3, 5, 6} London, United Kingdom	2003	Director of the Company; until March 2003, director of Talisman Energy Sweden AB (a wholly owned subsidiary of the Company); until 2001, held various international senior and executive management positions with BP plc (international integrated oil and gas company) including General Manager, Abu Dhabi Company for Onshore Oil Operations (ADCO), a BP joint venture; 1991 to 1994, Corporate Associate President, BP Indonesia; and 1990 to 1991, Corporate Head of Strategy for the BP Group based in London.
Al L. Flood, C.M. ^{1, 4} Thornhill, Ontario	2000	Director of various corporations; from June 1999 to March 2000, Chairman of the Executive Committee of Canadian Imperial Bank of Commerce ("CIBC") (a Canadian chartered bank); prior to June 1999, Chairman and Chief Executive Officer of CIBC and held various positions in the domestic and international operations of CIBC.
Dale G. Parker ^{1, 5} Vancouver, British Columbia	1993	Director of various corporations and public administration and financial institution advisor; prior to January 1998, President and Chief Executive Officer of Workers' Compensation Board of British Columbia; prior to November 1994, President of White Spot Limited (food services company) and Executive Vice-President of Shato Holdings Ltd. (food processing and services and real estate company); prior to November 1993, Executive Vice-President and Chief Financial Officer of Shato Holdings Ltd.; prior to November 1992, Chairman and Chief Executive Officer of British Columbia Financial Institutions Commission (regulator of financial institutions).

Name and Municipality of Residence	Year First Became Director of the Company	Present Principal Occupation or Employment (including all officer positions currently held with the Company) and Principal Occupation or Employment for the Past Five Years or More
Lawrence G. Tapp ^{3, 4} Langley, British Columbia	2001	Chairman of Tapp Technologies Inc. (wine label production company); director of various corporations; from 1995 to 2003, Dean of the Richard Ivey School of Business of the University of Western Ontario; from 1992 to 1995, Executive in Residence of the Faculty of Management and Adjunct Professor, University of Toronto; from 1985 to 1992, Vice Chairman, President and Chief Executive Officer of Lawson Mardon Group Limited (packaging conglomerate).
Stella M. Thompson ^{4, 5} Calgary, Alberta	1995	Principal of Governance West Inc. (corporate governance consulting company); President of Stellar Energy Ltd. (energy and management consulting company); director of various corporations; prior to June 1991, Vice-President, Planning, Business Information & Systems of Petro-Canada Products (petroleum refining and marketing company).
Robert G. Welty ^{1, 2} Calgary, Alberta	2003	Director and Chief Executive Officer of Sterling Resources Ltd. (oil and gas exploration and development company) since 1998; 1996 to 1997, President, Escondido Resources (International) Ltd. (oil and gas exploration company); 1994 to 1995, President and Chief Executive Officer of Canadian Fracmaster Ltd. (oil field service company); 1992 to 1994, President and Chief Executive Officer of Bow Valley Energy Inc. (oil and gas exploration and development company); 1976 to 1988, President and Chief Executive Officer of Asamera Inc. (oil and gas exploration and development company).
Charles W. Wilson ^{1, 2, 6} Evergreen, Colorado	2002	Director of various corporations; from 1993 to 1999, President and Chief Executive Officer of Shell Canada (integrated oil and gas company); from 1988 to 1993, Executive Vice President US Downstream Oil and Chemical of Shell Oil US (integrated oil and gas company); prior to 1988, Vice President US Refining and Marketing of Shell Oil US and held various positions in the domestic and international natural resource operations of Shell.

Notes:

- 1 Member of the Audit Committee.
- 2 Member of the Executive Committee.
- 3 Member of the Governance and Nominating Committee.
- 4 Member of the Management Succession and Compensation Committee.
- 5 Member of the Pension Funds Committee.
- 6 Member of the Reserves Committee.

Shareholdings of Directors and Officers

Information is given below with respect to the direct and indirect beneficial ownership of, or control or direction over, Common Shares of the Company (i) by each of the current directors and each nominee for election as director, (ii) by all current directors and all executive officers appointed by the Board of Directors, as a group and (iii) by all nominees for election as director and all executive officers appointed by the Board of Directors, as a group. Effective January 1, 2001, the Company adopted a Deferred Share Unit Plan to support the alignment of director and shareholder interests. Information is given below with respect to the deferred share unit holdings of certain directors. More information about the Deferred Share Unit Plan is provided in the section of this Circular under the heading "Remuneration of Directors".

Name of Beneficial Owner	Common Shares Beneficially Owned¹	Deferred Share Units
Douglas D. Baldwin	2,500	2,071
James W. Buckee	54,586	N/A
Kevin S. Dunne	500	0
Al L. Flood	5,000	2,419
Dale G. Parker	5,000	530
Roland Priddle	1,635	2,588
Lawrence G. Tapp	2,500	0
Stella M. Thompson	2,500	943
Robert G. Welty	2,500	0
Charles W. Wilson	1,000	0
Total for all current directors and all executive officers appointed by the Board of Directors	119,927	8,551 ³
Total for all nominees for election as director and all executive officers appointed by the Board of Directors	118,292 ²	N/A

Notes:

- 1 The information regarding Common Shares beneficially owned, directly or indirectly, over which control or direction is exercised, not being within the knowledge of the Company, has been supplied by all current directors and nominees for director and executive officers individually. The information is as of March 3, 2004.
- 2 Represents 0.0924% of Common Shares of the Company outstanding at March 3, 2004.
- 3 Deferred share units are held by non-employee directors only.

Appointment of Auditor

Shareholders will be asked at the Meeting to pass a resolution reappointing Ernst & Young LLP, Chartered Accountants, as auditor of the Company, to hold office until the next annual meeting of shareholders. To be effective, the resolution must be passed by a majority of the votes cast thereon by the shareholders at the Meeting. Ernst & Young LLP or its predecessor has been auditor of the Company or its predecessor since 1982.

Amendment of Articles – Three for One Division of Common Shares

At the Meeting, shareholders will be asked to vote on a special resolution (the “Special Resolution”) amending the Company’s Articles to divide the issued and outstanding Common Shares on a three for one basis (the “Share Split”).

Since 1998, the trading price of the Common Shares has increased from a high of \$45.60 (US \$32.19) to a high of over \$74 (over US \$57) in the last quarter of 2003. The trading price of Common Shares has continued to increase this year, recently reaching an all time high of \$81.80.

It is believed that Common Shares are owned primarily by institutions such as mutual funds, pension funds and life insurance companies and it is estimated that approximately 30% of the Common Shares are held by retail investors. The Board of Directors believes that the Share Split will encourage greater market liquidity and wider distribution among retail investors, as a lower share price makes a board lot more affordable.

The Share Split will not change the rights of holders of Common Shares. Each Common Share outstanding after the Share Split will be entitled to one vote and will be fully paid and nonassessable. As a result of the Share Split, there will be certain consequential amendments to outstanding rights and options to acquire Common Shares and to the Company’s share-based incentive compensation plans to preserve proportionately the rights of holders of outstanding rights and options and of plan participants.

Under existing Canadian income tax law and taking into account all published proposals for amendments, the proposed subdivision of Common Shares will not result in taxable income or in any gain or loss to the holders of Common Shares. In computing any gain or loss on the disposition of the Common Shares, holders of Common Shares will be required to reduce the adjusted cost base of each Common Share to an amount equal to one third of the adjusted cost base of each Common Share currently held.

Also, under existing United States federal income tax law, generally the proposed subdivision of Common Shares will not result in taxable income or in any gain or loss to the holders of Common Shares. The tax basis in the existing Common Shares generally will be allocated proportionately to the Common Shares held after the completion of the proposed subdivision, resulting in a tax basis in each Common Share that is one third of the basis of the Common Shares held immediately prior to the subdivision. The holding period of the Common Shares held after the proposed subdivision will include the holding period of the existing Common Shares for purposes of determining whether a subsequent sale of Common Shares qualifies as a short-term or long-term capital gain or loss. If a holder has two or more lots of Common Shares, bought at different dates and prices, special rules apply and the holder should consult his or her tax advisor regarding the method for allocating the tax basis and for determining the holding period of each Common Share. Other rules may apply to holders who are subject to special provisions under the U.S. Internal Revenue Code.

If the Special Resolution is passed at the Meeting and the Share Split is implemented, Articles of Amendment will be filed to divide the Common Shares and shareholders of record as of the close of business on a date to be determined by the Company, expected to be May 19, 2004 (the "Record Date"), will keep their current share certificates and will be provided with additional share certificates representing the Common Shares to which they are entitled as a result of the Share Split. It is currently expected that the Company or its transfer agent, Computershare Trust Company of Canada, will mail such certificates on or about May 25, 2004 (the "Mailing Date"). Currently outstanding share certificates representing Common Shares should be retained by the holders thereof and should not be forwarded to the Company or its transfer agent. Pursuant to the rules of the Toronto Stock Exchange, the Common Shares will commence trading on a subdivided basis at the opening of business on the second trading day preceding the Record Date. Pursuant to the rules of the New York Stock Exchange, the Common Shares will commence trading on a subdivided basis on that exchange one business day after the Mailing Date.

Shareholders voting against the Special Resolution are not entitled to exercise any statutory rights of dissent or similar appraisal remedies that would require the Company to repurchase their Common Shares if the Special Resolution is approved by shareholders and implemented by the Company.

To be effective, the resolution to amend the Articles to give effect to the Share Split must be passed by two-thirds of the votes cast thereon by the shareholders at the Meeting. The text of the Special Resolution is set out below. **The Board of Directors unanimously recommends that shareholders vote in favour of this resolution. The persons designated in the enclosed voting instruction form or form of proxy, unless instructed otherwise, intend to vote FOR the foregoing resolution.**

Text of Special Resolution

BE IT RESOLVED as a special resolution that:

1. Pursuant to section 173 of the Canada Business Corporations Act (the "Act"), the Articles of the Company be amended to divide the issued and outstanding Common Shares on a three for one basis;
2. Any one of the directors or officers of the Company is hereby authorized to sign all such documents, including, without limitation, Articles of Amendment, and to do all such acts and things, including, without limitation, delivering such Articles of Amendment to the Director under the Act, as such director or officer determines, in his or her discretion, to be necessary or advisable in order to properly implement and give effect to the foregoing; and
3. The directors of the Company may, in their discretion, without further approval of the shareholders, revoke this special resolution at any time before the issue of a Certificate of Amendment in respect of the foregoing.

INFORMATION RELATING TO THE COMPANY

Compensation of Directors and Executive Officers

Summary of Executive Compensation

Aggregate Compensation

During the financial year ended December 31, 2003, there were ten¹ Executive Officers of the Company who received, in aggregate, cash remuneration of \$6,477,772. Cash payments made through the Employee Stock Option Plan are reported in Table 3. For this purpose, "Executive Officers" means the President and Chief Executive Officer, and Executive Vice-Presidents in charge of a principal business unit or function of the Company or its subsidiaries. The aggregate value of all other remuneration furnished to the ten Executive Officers during the financial year was \$2,540,133 comprised of the value of Company-supplied vehicles and parking, as well as club memberships, financial counseling, service awards, vacation pay, separation payments, and provincial health care premiums paid by the Company on behalf of the Executive Officers.

1 Two Executive Officers, Dr. E.W. Bogle and Dr. R.W. Mitchell, left the Company in June 2003 and September 2003, respectively.

Individual Compensation

The following table sets forth all annual and long-term compensation of the individuals who were, at December 31, 2003, the Chief Executive Officer and the next four most highly compensated Executive Officers (collectively the "Named Executive Officers"), for the 2003, 2002, and 2001 financial years of the Company.

Table 1: Summary Compensation

Name and Principal Position ¹	Year	Annual Compensation			Long-term Compensation Awards	All Other Compensation ⁴ (\$)
		Salary (\$)	Bonus/ Variable Pay ² (\$)	Other Annual Compensation ³ (\$)	Common Shares Under Option Grants (#)	
President and Chief Executive Officer	2003	997,500	1,468,077 ⁶	—	100,000	86,603
James W. Buckee	2002	945,500	681,000	—	110,000	78,355
	2001	809,334	566,600	—	90,000	76,261
Executive Vice-President, Frontier and International Operations	2003	470,000	482,748 ^{5,6}	—	35,000	36,927
T. Nigel D. Hares	2002	449,600	215,328 ⁵	—	40,000	35,394
	2001	390,784	203,625 ⁵	—	30,000	35,228
Executive Vice-President, Corporate and Legal, and Corporate Secretary	2003	435,000	511,827 ^{5,6}	—	35,000	34,427
M. Jacqueline Sheppard	2002	410,975	200,328 ⁵	—	40,000	33,683
	2001	346,159	208,025 ⁵	—	30,000	31,507
Executive Vice-President, Finance and Chief Financial Officer	2003	393,750	427,368 ^{5,6}	—	35,000	31,614
Michael D. McDonald	2002	366,800	185,328 ⁵	—	40,000	29,369
	2001	296,211	65,925 ⁵	—	30,000	26,722
Executive Vice-President, Corporate Services	2003	387,750	403,797 ⁶	—	35,000	30,814
Robert M. Redgate	2002	371,175	188,100	—	40,000	30,712
	2001	324,225	216,900	—	30,000	29,660

Notes:

- 1 In early 2003, the Company changed the titles of all its vice-presidents to better reflect the roles and responsibilities of their continuing offices.
- 2 Amounts listed are variable pay unless otherwise noted. Variable pay for 2003 is payable on April 1, 2004.
- 3 Perquisites and other personal benefits do not exceed the lesser of \$50,000 and 10 percent of the total annual salary and bonus of the Named Executive Officers.
- 4 Includes the value of the Talisman Savings Plan contributions and life insurance premiums paid by Talisman on behalf of the Named Executive Officers.
- 5 Includes a non-pensionable Holiday bonus of \$325.21 in 2001, \$327.86 in 2002, and \$327.87 in 2003.
- 6 Includes a non-pensionable one-time discretionary bonus, described under the 2003 Executive Compensation section, of \$95,517 for James W. Buckee, \$45,320 for T. Nigel D. Hares, \$41,699 for M. Jacqueline Sheppard, \$37,227 for Michael D. McDonald, and \$37,373 for Robert M. Redgate.

Stock Option Program

The following table sets forth stock options granted under the Company's Employee Stock Option Plan (the "Plan") during the financial year ended December 31, 2003 to each of the Named Executive Officers. Further information as to the operation of the Plan is set forth under the Management Succession and Compensation Committee Report below.

Table 2: Option/SAR Grants During 2003

	Common Shares Under Options Granted (#) ¹	% of Total Options Granted to Employees in 2003	Exercise Price (\$/Common Share)	Market Value of Common Shares on the Date of Grant ² (\$/Common Share)	Expiration Date
James W. Buckee	100,000	4.28%	\$59.415	\$59.415	March 6, 2013
T. Nigel D. Hares	35,000	1.50%	\$59.415	\$59.415	March 6, 2013
M. Jacqueline Sheppard	35,000	1.50%	\$59.415	\$59.415	March 6, 2013
Michael D. McDonald	35,000	1.50%	\$59.415	\$59.415	March 6, 2013
Robert M. Redgate	35,000	1.50%	\$59.415	\$59.415	March 6, 2013

Notes:

- 1 The options were granted on March 7, 2003 and vest three years from the date of grant. The options include the cash payment feature (tandem Stock Appreciation Right (SAR)), described under the Compensation Program Design section.
- 2 Determined by calculating the mean of the high and low reported prices at which Common Shares were traded on the Toronto Stock Exchange (the "TSX") on the day prior to the date of grant.

At December 31, 2003, 1,746,100 options to acquire Common Shares of the Company were held by individuals who were Executive Officers of the Company during 2003. Including the options described in Table 2, options to acquire a total of 407,900 Common Shares were granted during 2003 to ten Executive Officers at a weighted average price of \$59.415.

The following table sets out the details of options exercised and the aggregate value realized by the particular Named Executive Officer during 2003 and, in addition, sets out the aggregate number of outstanding exercisable options owned by each of the Named Executive Officers, categorized as being either exercisable or unexercisable as at December 31, 2003, together with the value of such options at the end of the year.

Table 3: Aggregated Option/SAR Exercises During 2003 and Option Values

Name	Common Shares Acquired/ Options Surrendered on Exercise ¹	Aggregate Value Realized ² (\$)	Unexercised Options at December 31, 2003 (#)		Value of Unexercised in-the-Money Options at December 31, 2003 ³ (\$)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
James W. Buckee	110,000	4,639,350	316,000	300,000	11,436,345	3,725,250
T. Nigel D. Hares	—	—	113,650	105,000	4,259,377	1,294,575
M. Jacqueline Sheppard	35,000	1,340,775	113,650	105,000	4,259,377	1,294,575
Michael D. McDonald	58,650	1,790,219	—	105,000	—	1,294,575
Robert M. Redgate	23,650	713,479	70,000	105,000	2,844,150	1,294,575

Notes:

- 1 Represents the number of shares acquired on exercise, or the number of options surrendered for cancellation as a result of electing to receive the equivalent value as a cash payment.
- 2 Calculated by subtracting the exercise price of the option from the market price obtained per option exercised, or surrendered for cash payment, on the date of the exercise, and by multiplying that amount by the number of Common Shares under options exercised or surrendered.
- 3 Calculated by subtracting from the closing price per share of the Company's Common Shares on the TSX on December 31, 2003, the exercise price of the option and by multiplying that amount by the number of Common Shares under options owned. The closing trading price of the Company's Common Shares on the TSX on December 31, 2003 was \$73.52.

Defined Benefit Pension Plan

The Company provides all of the Named Executive Officers with retirement benefits through two plans, both of which are non-contributory defined benefits plans:

- a registered defined benefit plan called the Supplementary Pension Plan for Executives of Talisman (the "Supplementary Pension Plan"), and
- special pension agreement (the "Special Pension Agreement") funded through a Retirement Compensation Arrangement. The Special Pension Agreement is a non-registered plan which provides pension payments that would otherwise be payable under the Supplementary Pension Plan but which exceed the prescribed maximum allowable under the *Income Tax Act*.

In addition to the Named Executive Officers listed in Table 1, five other Executive Officers participated in the Supplementary Pension Plan and Special Pension Agreement in 2003.

The Supplementary Pension Plan and Special Pension Agreement are non-contributory, defined benefit plans which provide for an annual accrual of 2% of the total of Best Average Earnings and Final Average Award. "Best Average Earnings" means the average of the best three years' compensation (actual base pay for the three year period prior to January 1, 2004). "Final Average Award" means the average of the variable pay awarded during the four consecutive years prior to December 31, 2003.

Table 4 shows the estimated annual pension payments for participants in both the Supplementary Pension Plan and Special Pension Agreement. Table 5 shows the portion of the total estimated annual pension payments that are provided through the Supplementary Pension Plan.

Table 4: Annual Pension Payments (\$) to Participants in both the Supplementary Pension Plan and the Special Pension Agreement

Remuneration ¹	Years of Service						
	15	20	25	30	35	40	45
350,000	105,000	140,000	175,000	210,000	245,000	280,000	315,000
400,000	120,000	160,000	200,000	240,000	280,000	320,000	360,000
450,000	135,000	180,000	225,000	270,000	315,000	360,000	405,000
500,000	150,000	200,000	250,000	300,000	350,000	400,000	450,000
550,000	165,000	220,000	275,000	330,000	385,000	440,000	495,000
600,000	180,000	240,000	300,000	360,000	420,000	480,000	540,000
650,000	195,000	260,000	325,000	390,000	455,000	520,000	585,000
700,000	210,000	280,000	350,000	420,000	490,000	560,000	630,000
750,000	225,000	300,000	375,000	450,000	525,000	600,000	675,000
800,000	240,000	320,000	400,000	480,000	560,000	640,000	720,000
850,000	255,000	340,000	425,000	510,000	595,000	680,000	765,000
900,000	270,000	360,000	450,000	540,000	630,000	720,000	810,000
950,000	285,000	380,000	475,000	570,000	665,000	760,000	855,000
1,000,000	300,000	400,000	500,000	600,000	700,000	800,000	900,000
1,050,000	315,000	420,000	525,000	630,000	735,000	840,000	945,000
1,100,000	330,000	440,000	550,000	660,000	770,000	880,000	990,000
1,150,000	345,000	460,000	575,000	690,000	805,000	920,000	1,035,000
1,200,000	360,000	480,000	600,000	720,000	840,000	960,000	1,080,000
1,250,000	375,000	500,000	625,000	750,000	875,000	1,000,000	1,125,000
1,300,000	390,000	520,000	650,000	780,000	910,000	1,040,000	1,170,000
1,350,000	405,000	540,000	675,000	810,000	945,000	1,080,000	1,215,000
1,400,000	420,000	560,000	700,000	840,000	980,000	1,120,000	1,260,000
1,450,000	435,000	580,000	725,000	870,000	1,015,000	1,160,000	1,305,000
1,500,000	450,000	600,000	750,000	900,000	1,050,000	1,200,000	1,350,000
1,550,000	465,000	620,000	775,000	930,000	1,085,000	1,240,000	1,395,000
1,600,000	480,000	640,000	800,000	960,000	1,120,000	1,280,000	1,440,000
1,650,000	495,000	660,000	825,000	990,000	1,155,000	1,320,000	1,485,000
1,700,000	510,000	680,000	850,000	1,020,000	1,190,000	1,360,000	1,530,000
1,750,000	525,000	700,000	875,000	1,050,000	1,225,000	1,400,000	1,575,000
1,800,000	540,000	720,000	900,000	1,080,000	1,260,000	1,440,000	1,620,000
1,850,000	555,000	740,000	925,000	1,110,000	1,295,000	1,480,000	1,665,000

Note:

1 Includes Best Average Earnings plus Final Average Award.

Years of service credited in the Supplementary Pension Plan and Special Pension Agreement where applicable, as at December 31, 2003, are as follows: James W. Buckee – 26.58; T. Nigel D. Hares – 9.33; M. Jacqueline Sheppard – 10.33; Michael D. McDonald – 6.00, and Robert M. Redgate – 25.50. Years of service credited on normal retirement at age 65 would be as follows: James W. Buckee – 33.92; T. Nigel D. Hares – 21.33; M. Jacqueline Sheppard – 27.42; Michael D. McDonald – 18.75; and Robert M. Redgate – 41.00.

James W. Buckee's pension payable from the Supplementary Pension Plan and Special Pension Agreement will be reduced by the pension formula applicable to and an amount payable by a previous employer for the period May 1977 to June 1992. Michael D. McDonald has been granted a pension enhancement recognizing the difference between employee and Supplemental Pension Plan benefits for the period prior to his enrollment in the Supplemental Pension Plan in January 1998. Pensions payable are in the form of a life annuity, with a 60% survivor benefit provided to the surviving spouse in the event of death of the Named Executive Officer. The benefits listed above are not subject to any offsets such as Canada Pension Plan or Old Age Security.

Table 5: Annual Pension Payments to Participants from the Supplementary Pension Plan

Remuneration ¹	Years of Service						
	15	20	25	30	35	40	45
\$350,000 - \$1,850,000	\$25,833	\$34,444	\$43,056	\$51,667	\$60,278	\$68,889	\$77,500

Note:

1 Includes Best Average Earnings plus Final Average Award.

Employment Contracts and Termination of Employment Arrangements

At December 31, 2003, the Company had employment contracts in place for all Executive Vice-Presidents of the Company. The contracts provide for the payment of two years' compensation (including base salary plus target variable pay, plus benefits) in the event of a change in control of the Company. An employment contract with the President and Chief Executive Officer provides for two and one half years' compensation (including base salary plus target variable pay, plus benefits) in the event of a change in control of the Company.

The Employee Stock Option Agreement also allows for the full vesting of all unvested options for all optionees in the event of a change in control.

Composition and Role of the Management Succession and Compensation Committee

The Company's executive compensation program is administered by the Management Succession and Compensation Committee (the "Compensation Committee") of the Board of Directors. The Compensation Committee has, as part of its mandate, responsibility for the remuneration of the Executive Officers of the Company. The Compensation Committee also evaluates the performance of the Company's Executive Officers and reviews the design and competitiveness of the Company's incentive compensation programs. Until May 6, 2003, the members of the Compensation Committee were: Paul J. Hoenmans, David E. Powell, Lawrence G. Tapp and Stella M. Thompson. Following May 6, 2003 the members were: Douglas D. Baldwin, Al L. Flood, Lawrence G. Tapp, and Stella M. Thompson. None of the members of the Compensation Committee is, or has ever been, an officer or an employee of the Company or any of its subsidiaries. The Compensation Committee meets at least twice annually or more often as needed. The Compensation Committee met five times in 2003.

Management Succession and Compensation Committee Report

Introduction and Objectives

The compensation philosophy of the Company is to reward employees, including the Chief Executive Officer and all Executive Officers, commensurate with personal achievements and the success of the Company. In doing so, all salaried employees place an element of compensation at risk. This provides the Company with flexibility and the individual with incentive to out-perform expectations. The objectives of the compensation program are to attract, retain and motivate high-quality staff and to provide a sense of proprietorship.

Compensation Program Design

Total compensation for all salaried staff including the Chief Executive Officer and all Executive Officers consists of four elements: base pay, variable pay (both of which are paid in cash), long-term incentives and benefits. Variable pay is an integral element of compensation necessary to keep an individual's total compensation at a competitive level. The levels of variable pay (as a percentage of actual base earnings) are as follows:

Position	2003 Variable Pay Target	2003 Variable Pay Range
President and Chief Executive Officer	80%	0-160%
Other Executive Officers	60%	0-120%

The combination of base pay and variable pay targets is referred to as "target total cash compensation" and is the basis on which market competitiveness is evaluated. For 2003, target total cash compensation was aimed at the top quartile of a comparable group of select senior oil and gas producers.

The compensation system is designed to ensure that total cash compensation received by the Chief Executive Officer and Executive Officers, as with all salaried staff, will be significantly higher than comparable positions in comparable companies when the Company performs well, and significantly lower than the market total cash compensation if the Company under-performs. The weighting of corporate financial and operational objectives versus individual leadership and strategic objectives in determining variable pay is split 70/30 for the Chief Executive

Officer and 50/50 for the Executive Officers. Corporate objectives relate to factors including, but not limited to, cash flow per share, income, reserves, production volumes, capital expenditures, per barrel of oil equivalent costs (finding and development, operating and general and administrative), share price appreciation relative to select senior oil and gas producers, as well as health, safety and environmental performance. Measurable and defined objectives are set annually to address these standards and other strategic initiatives. The Compensation Committee also applies a subjective analysis of strategic leadership issues in determining final total cash compensation. Variable pay owing in respect of the current year is paid in a lump sum in April of the following year after a full assessment of individual and corporate results.

The long-term incentive program is comprised of stock options granted annually by the Compensation Committee to the Named Executive Officers as shown in Tables 2 and 3 and other employees. The program only has value to the extent that additional shareholder value is created over time. Stock options are viewed as an important aspect of total compensation for senior staff, serving to align the interest of executives with those of the shareholders. Option grants increase with the employee's level in the Company.

The Company amended all outstanding stock options in 2003 to include a cash payment feature (tandem Stock Appreciation Right (SAR)). Specifically, the cash payment feature provides the optionholder the right to surrender the exercisable option for cancellation in return for a cash payment from the Company. The cash payment is based on the number of options cancelled, multiplied by the amount by which the market price of the Common Shares at the time of surrender exceeds the strike price of the option. The inclusion of the cash payment feature in options granted enables the Company to provide similar benefits to optionholders without increasing the outstanding Common Shares, to the extent that optionholders utilize this feature. Since inception, 99% of the options exercised have utilized the cash payment feature.

Options are granted at the market value of the Common Shares on the day prior to the date of the grant and in a number that is at or above the median value of long-term incentives provided by upstream oil and gas industry companies, as reported through independent consulting surveys which are reviewed prior to grant. Option grants can be increased to respond to specific corporate or individual circumstances as a means of increasing incentive. Options normally vest after three years and expire if not exercised within ten years of issuance.

In addition to base pay, variable pay and stock options, various perquisites and other benefits are provided on a market competitive basis. Executive Officers are also eligible to receive non-pensionable performance bonuses. These bonuses are usually project-related and acknowledge extraordinary achievements. In March 2003, the Board of Directors approved a discretionary 10% cash bonus for all permanent employees, including Executive Officers, in recognition of the very strong financial performance sustained through 2002 and into 2003. Amounts paid to executive officers are included in Table 1.

2003 Executive Compensation

Total compensation of the Named Executive Officers was reviewed at the Compensation Committee meeting in March 2003. The Compensation Committee approved market adjustments to base salaries for Named Executive Officers at that time, following a review of the peer group of companies used to establish compensation levels for the executive group. This peer group consists of oil and gas companies of similar size and with similar international challenges as Talisman. This international comparator group reflects the combined domestic and international scope of responsibilities at the executive level and the broader geographic employment market. Variable pay targets increased, effective January 1, 2003, to 60% for the Named Executive Officers, other than the CEO, to align current competitiveness on a target total cash basis.

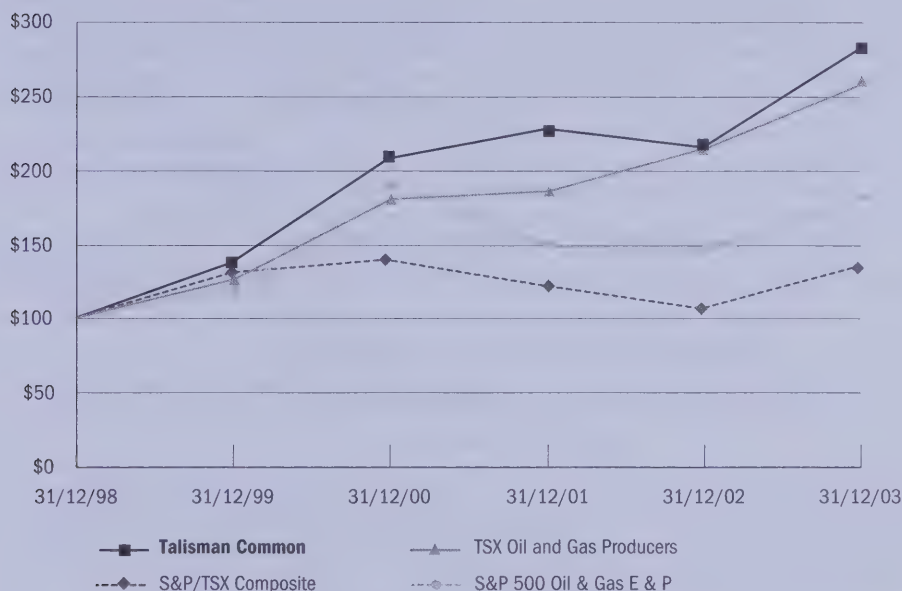
In determining the 2003 variable pay for all Executive Officers, the Compensation Committee reviewed 2003 corporate performance against targets previously set out for financial and operational measures outlined under the heading "Compensation Program Design". The Compensation Committee also reviewed the individual performance of all Executive Officers in 2003 against their individual financial, operational, strategic and leadership targets established on January 1, 2003, which are a subset of the corporate performance targets. Based on these detailed reviews, variable payouts for 2003 performance were approved, as shown in Table 1 and will be paid on April 1, 2004. These payouts are above target levels, reflecting a very successful year of financial and operational results that included record cash flow and earnings, and share price performance well above the Company's peer group.

Submitted by the Management Succession and Compensation Committee of the Board of Directors of Talisman Energy Inc.

Al L. Flood, Chairman
Douglas D. Baldwin
Lawrence G. Tapp
Stella M. Thompson

Performance Graph

The following graph shows the performance of Common Shares relative to the S&P/TSX Composite, the TSX Oil and Gas Producers and the S&P 500 Oil and Gas Exploration and Production indices from the period December 31, 1998 to December 31, 2003.



\$100 Investment In Base Period	1998	1999	2000	At December 31 2001	2002	2003	Annual Average Return
Talisman Common Shares ¹	100	136.92	206.49	226.77	215.16	281.14	22.97%
TSX Oil and Gas Producers Total Return Index	100	122.52	179.48	184.27	215.69	259.70	21.03%
S&P/TSX Composite Total Return Index	100	131.71	141.47	123.69	108.30	137.25	6.54%
S&P 500 – Oil and Gas E&P Total Return Index	100	119.33	189.18	149.54	147.34	181.87	12.71%

Note:

1 Assumes dividends are reinvested.

Remuneration of Directors

For the year ended December 31, 2003, each non-employee director of the Company, other than the Chairman of the Board, was paid an annual fee of \$28,000. The Chairman of the Board received an annual fee of \$160,000, and was provided Company-paid office space and reimbursement of related office expenses. Each director also received an attendance fee of \$1,500 for each regular meeting of the Board of Directors attended. In addition, each committee member was paid an annual fee of \$3,200 for each regular committee on which he or she served (\$6,700 for the Chair of a committee) and an attendance fee of \$1,500 for each committee meeting attended. Each director also received a fee of \$800 for each special board and committee meeting held. Directors residing outside of Canada receive the same nominal fees described above, but in U.S. funds.

The Company adopted a Deferred Share Unit Plan for non-employee directors (the "DSU Plan") effective January 1, 2001. Under the DSU Plan, non-employee directors of the Company may elect, on an annual basis, to receive all or part of their compensation in the form of deferred share units. The DSU Plan enhances the alignment of director and shareholder interests in that the value of the units directly tracks the performance of the Common Shares. Under the DSU Plan, deferred share units are allocated to a notional account on a quarterly basis by dividing the amount of compensation that the director has elected to receive in deferred share units by the market value of the Company's

Common Shares. A participant in the DSU Plan is not entitled to the benefit of the value of his or her DSU Plan account until such time as the participant ceases to be a director of the Company. No shares are issued under this plan. In 2003, five non-employee directors participated in the DSU Plan.

Non-employee directors are eligible to participate in the Director Stock Option Plan, implemented in 1998. Between 1993 and 1998, directors were eligible to participate in the Employee Stock Option Plan. The Director Stock Option Plan was amended in 2003 to include the cash payment feature, described under the Compensation Program Design section, on all existing and future options. During 2003, Kevin S. Dunne, Robert G. Welty, and Charles W. Wilson received 10,000 options each, at a weighted average price of \$56.80. All other directors received 5,000 options, with the exception of Dale Parker, who declined the options, and Douglas D. Baldwin who received 7,000 options, at a weighted average price of \$59.415. Options are fully vested after three years and expire if not exercised within ten years of issuance.

In addition, directors are reimbursed for their Company-related travel expenses. The Director who is a full-time salaried employee of the Company received no remuneration for serving as a director of the Company.

Indebtedness of Directors and Officers

No director, proposed nominee for director or officer, or any of their associates, is or has been indebted to the Company at any time since December 31, 2002.

Statement of Corporate Governance Practices

The Company's Statement of Corporate Governance Practices is set out in Schedule A to this Circular.

Shareholder Proposals

A shareholder intending to submit a proposal at an annual meeting must comply with applicable provisions of the *Canada Business Corporations Act*. The Company will include a shareholder proposal in management's proxy circular prepared in connection with the annual meeting of shareholders in 2005 provided that such a proposal is received by the Corporate Secretary in the Company's principal executive office on or before December 3, 2004 and provided that such a proposal is required to be included in the Company's management proxy circular pursuant to the applicable terms of the *Canada Business Corporations Act*.

Directors' and Officers' Liability Insurance


The Company carries directors' and officers' liability insurance to a maximum of US\$50,000,000 per claim, subject to an aggregate annual limit of US\$50,000,000 for all directors and officers. This policy covers all directors and officers of the Company and its subsidiaries. There is no deductible applicable to the policy. The premium payable by the Company for the year January 1, 2004 to January 1, 2005 is US\$290,000. Neither directors nor officers will pay any portion of the premium.

Additional Information

Copies of this Circular, the Annual Report which contains the comparative audited consolidated financial statements of the Company, any interim financial statements of the Company subsequent to those statements contained in the Annual Report, and the Company's Annual Information Form for the fiscal year ended December 31, 2003, as filed with Canadian securities commissions and with the United States Securities and Exchange Commission under Form 40-F, may be obtained without charge by contacting the Investor and Corporate Communications Department, Talisman Energy Inc., Suite 3400, 888 Third Street S.W., Calgary, Alberta, T2P 5C5, or by e-mail at tim@talisman-energy.com.

DIRECTORS' APPROVAL

The contents and the sending of this Circular have been approved by the directors of the Company.



M. Jacqueline Sheppard
Corporate Secretary

March 3, 2004

SCHEDULE A – STATEMENT OF CORPORATE GOVERNANCE PRACTICES

Talisman's corporate governance practices satisfy all the existing guidelines for effective corporate governance established by the Toronto Stock Exchange ("TSX") and substantially all of the New York Stock Exchange corporate governance listing standards applicable to U.S. companies. The following statement addresses the principal matters relating to the Company's corporate governance practices. The TSX corporate governance guidelines and Talisman's compliance with these guidelines is shown in tabular form at the end of this disclosure. Mandates of the Board, its committees, the Chairman and the Chief Executive Officer may be obtained from the Company website or upon request from: Investor and Corporate Communications Department, Talisman Energy Inc., Suite 3400, 888 Third Street S.W., Calgary, Alberta, T2P 5C5, e-mail: tlm@talisman-energy.com.

Independence of the Board

Talisman is in full compliance with the TSX recommendation that "The board of directors of every corporation should be constituted with a majority of individuals who qualify as unrelated directors. An unrelated director is a director who is independent of management and is free from any interest and any business or other relationship which could, or could reasonably be perceived to, materially interfere with the director's ability to act with a view to the best interests of the corporation, other than interests and relationships arising from shareholding." In 2003, the Board of Directors of Talisman comprised 10 directors, nine of whom, including the Chairman of the Board, qualified as unrelated directors as defined by the TSX. The only related director is James W. Buckee, President and Chief Executive Officer of the Company.

In addition, in accordance with a New York Stock Exchange rule that listed companies must have a majority of independent directors, the Board has determined that none of the nine unrelated directors has any material relationship with the Company (other than serving as a director of the Company) and that all nine unrelated directors are independent. Two directors, Al Flood and Doug Baldwin, have relationships with the Company through their directorships and shareholdings with the Canadian Imperial Bank of Commerce ("CIBC") and TransCanada PipeLines Limited ("TransCanada"), respectively. Talisman has various business dealings with both CIBC and TransCanada. The Board of Directors determined that neither Mr. Flood's nor Mr. Baldwin's relationship with Talisman is material, principally on the grounds that (i) the relationships Talisman has with each of CIBC and TransCanada were entered into on terms substantially similar to those that would be offered to comparable counterparties in similar circumstances; and (ii) the termination of either relationship in the normal course of business would not reasonably be expected to have a material and adverse effect on the financial condition, results of operations or business of CIBC or TransCanada. Accordingly, Talisman's relationship with each of CIBC and TransCanada does not compromise Mr. Flood's and Mr. Baldwin's independence, respectively.

The composition of the Board, including the independence of the Chairman and his specified role, ensures that the Board has in place appropriate structures and procedures to ensure that the Board can function independently of management. All committees of the Board of Directors are composed entirely of unrelated, independent directors with the exception of the Executive Committee, the majority of whose members are unrelated and independent.

The Chairman of the Board is specifically charged with responsibility for leading and managing the Board in discharging its responsibilities. Annually, the Chairman conducts an evaluation of the effectiveness of the Board, its committees and the individual directors. He then reports his findings to the Governance and Nominating Committee and to the full Board and seeks Board approval to implement any recommendations that may result from this process. The Chair of the Governance and Nominating Committee evaluates the effectiveness of the Chairman annually. The Chairman's mandate directs him to ensure that the directors hold regular discussions without management present and he presides at such sessions. In addition, the Chairman acts as the Board's communicator with management.

Responsibilities of the Board

The Board of Directors of Talisman sees its principal role as stewardship of the Company and its fundamental objective as the creation of shareholder value, including the protection and enhancement of the value of the Company's assets. The Board's stewardship responsibility means that it oversees the conduct of the business and management, which is responsible for developing long-term strategy and conducting the Company's day-to-day business. Annually, the Board meets at an extended Board session to review corporate strategy. The Board assesses and ensures systems are in place to manage the risks of the Company's business with the objective of preserving the Company's assets. The Board, through the Chief Executive Officer, sets the attitude and disposition of the Company towards compliance with applicable laws, environmental, safety and health policies, financial practices and reporting. In addition to its primary accountability to shareholders, the Board is also accountable to employees, government authorities, other stakeholders and the public.

In fulfilling its primary responsibilities, the Board ensures that the Company has:

- established long-term goals and a strategic planning process,
- identified the principal risks of the Company's business and implemented appropriate systems to monitor and manage those risks,
- established processes to manage and measure management's, and in particular, the Chief Executive Officer's performance in achieving the Company's stated objectives, including appropriate training, development and succession planning,
- established internal controls and management systems to effectively monitor the Company's operations and ensure compliance with applicable laws, regulations and policies,
- implemented processes to properly oversee Company sponsored pension plans, and
- developed and implemented a communications program for effectively communicating with and receiving feedback from shareholders, employees, government authorities, other stakeholders and the public.

The Board of Directors may delegate authority over certain matters to a committee of the Board, provided that certain responsibilities of the Board are sufficiently important to warrant the attention of the full Board and, accordingly, are not delegated or are only delegated in a qualified or partial manner, including:

- submitting to shareholders any matter requiring their approval,
- filling vacancies among the directors or appointing additional directors,
- issuing securities, declaring dividends or repurchasing the Company's own shares,
- approving management proxy circulars,
- approving annual financial statements,
- approving the annual statement of reserves data and other oil and gas information and reports thereon, and
- adopting, amending or repealing by-laws.

The Board of Directors has developed a mandate for the Board embodying the foregoing. A copy of this mandate may be obtained from Talisman's website at www.talisman-energy.com. To assist Board members in performing their responsibilities, the Company has adopted a policy whereby, with the approval of the Governance and Nominating Committee, a Board member may engage an outside advisor at the Company's expense.

The Board of Directors met seven times during the 2003 fiscal year. One director was unable to attend two meetings of the Board.

Committees of the Board

The Board of Directors has established six committees: the Audit Committee, the Executive Committee, the Governance and Nominating Committee, the Management Succession and Compensation Committee, the Pension Funds Committee and the Reserves Committee. The latter is a new committee of the Board having been formed in July 2003 to address many of the new board responsibilities prescribed by new National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. In accordance with the TSX guidelines, and as a result of the composition of the Board, all committees comprise a majority of unrelated, independent directors. The President and Chief Executive Officer is the only related director on the Board and is a member of the Executive Committee. All other committees are composed exclusively of unrelated, independent directors. With the exception of the Executive Committee, for which there are no regularly scheduled meetings, the committees of the Board convene in accordance with an annually developed schedule.

The Terms of Reference of the committees of the Board may be obtained from Talisman's website at www.talisman-energy.com.

Audit Committee

Members: The Audit Committee consists of **Al L. Flood**, **Dale G. Parker¹**, **Robert G. Welty** and **Charles W. Wilson**, all of whom are unrelated, independent directors. One member of the Audit Committee simultaneously serves on the audit committees of more than three public companies. The Board has determined that such simultaneous service does not impair the ability of this member to effectively serve on Talisman's Audit Committee.

Mandate: The primary roles and responsibilities of the Audit Committee include:

- reviewing and recommending to the Board for approval, the Company's annual financial statements and the related management's discussion and analysis,
- reviewing and approving the Company's interim financial statements and the related management's discussion and analysis,
- reviewing and approving, as prescribed, other financial information,
- recommending to the Board the auditors who will be proposed at the annual shareholders' meeting for appointment as the Company's external auditors for the ensuing year,
- evaluating and ensuring the independence of the Company's auditors,

Note:

¹ Denotes Committee Chair.

- reviewing and pre-approving the terms of the annual external audit engagement plan, as well as non-audit services the auditors are to perform,
- reviewing results of external audit activities,
- reviewing the Company's ongoing relationship with its auditors,
- maintaining direct access to the Company's internal and external auditors and meeting separately with each group,
- overseeing the internal audit function of the Company and its relationship with the Company's auditors and management,
- reviewing and obtaining reasonable assurance that the Company's internal financial control and information systems are properly designed and effectively implemented to produce accurate, appropriate and timely financial information,
- reviewing insurance coverage of significant business risks,
- receiving a report on the Company's material subsidiaries concerning any material non-routine structures,
- reviewing corporate policies within the scope of its responsibility and monitoring compliance with such policies,
- directing and supervising the investigation into any matter brought to the Committee's attention within the scope of its duties, and
- reporting to the Board at each regularly scheduled meeting following any Audit Committee meeting.

The Audit Committee has the authority to engage independent counsel and other advisers having special competencies, as it determines necessary to carry out its duties, and it determines the appropriate amount of funding the Company is to provide for compensation of such advisors.

Activities: The Audit Committee met five times in 2003. All members attended each meeting of the Committee.

Audit Committee Report

The following report of the Audit Committee of the Company shall not be deemed to be "soliciting material" or to be "filed" with the Canadian securities regulators or the U.S. Securities and Exchange Commission ("SEC"), nor shall this report be incorporated by reference into any filing made by the Company under the U.S. Securities Act of 1933, as amended, or the U.S. Securities Act of 1934, as amended.

The Audit Committee met with management and the independent auditor to review and discuss the December 31, 2003 financial statements. The Audit Committee also discussed with the independent auditor the matters included in the U.S. Statement on Auditing Standards No. 61 (Communication with Audit Committees). The Audit Committee has also received written disclosures from the independent auditor included in the U.S. Independence Standards Board Standard No. 1 (Independence Discussions with Audit Committees), and the Audit Committee discussed with the independent auditor that firm's independence.

Based upon the Audit Committee's review and discussions with management and the independent auditor, and the Audit Committee's review of the representations of management and the independent auditor, the Audit Committee recommended that the Board of Directors approve the audited consolidated financial statements for filing with the Canadian securities regulators and the SEC, and include the audited consolidated financial statements in the Company's Annual Report to shareholders for the year ended December 31, 2003.

The Audit Committee
Dale G. Parker, Chair
Al L. Flood
Robert G. Welty
Charles W. Wilson

Audit Fees and Pre-Approval of Audit Services

The following table presents fees for the audits of the Company's annual consolidated financial statements for 2003 and 2002 and for other services provided by Ernst & Young LLP.

	2003	2002
Audit fees	\$1,690,200	\$1,583,400
Audit-related fees	\$409,000	\$603,500
Tax fees	\$1,147,400	\$3,773,800
All other fees	\$92,400	\$59,000

The audit-related fees are primarily for prospectus filings, pension plan audits and attestation procedures related to cost certifications and government compliance. Tax fees are primarily for tax compliance and tax advisory services. All other fees are primarily for advisory services. The Audit Committee has concluded that the provision of tax services is compatible with maintaining Ernst & Young LLP's independence.

Under the terms of reference of the Audit Committee of the Board of Directors as amended in 2002, the Audit Committee is required to review and pre-approve the objectives and scope of the external audit work and proposed fees. In addition, the Audit Committee is required to review and pre-approve all non-audit services, including tax services, the Company's external auditors are to perform.

During 2003, the Audit Committee implemented specific procedures regarding the pre-approval of services to be provided by the Company's external auditors. These procedures specify certain prohibited services that are not to be performed by the Company's external auditors. In addition, these procedures require that at least annually, prior to the period in which the services are proposed to be provided, the Company's management, in conjunction with the Company's external auditors, prepares and submits to the Audit Committee a complete list of all proposed services and related fees to be provided to the Company by the Company's external auditors. Under the Audit Committee pre-approval procedures, for those services proposed to be provided by the Company's external auditors that have not been previously approved by the Audit Committee, the Audit Committee has delegated to the Chairman of the Audit Committee the authority to grant pre-approvals of such services. The decision to pre-approve a service covered under this procedure is presented to the full Audit Committee at the next scheduled meeting. At each of the Audit Committee's regular meetings, the Audit Committee is provided an update as to the status of services previously pre-approved.

Pursuant to these procedures since their implementation in 2003, 100% of each of the services relating to the fees reported as audit-related, tax and all other were pre-approved by the Audit Committee or its delegate, the Chair of the Audit Committee.

Executive Committee

Members: The Executive Committee consists of **Douglas D. Baldwin¹**, **James W. Buckee**, **Robert G. Welty** and **Charles W. Wilson**, of whom only James W. Buckee is a related, non-independent director.

Mandate: The Executive Committee is an extension of the full Board and convenes to take action when it is not practicable to call a meeting of the full Board. Consequently, the Executive Committee has no regularly scheduled meetings. The Executive Committee may exercise, subject to applicable laws, all of the powers and discretions of the full Board, provided that the powers of the Committee do not include those listed previously as warranting the attention of the full Board.

Activities: The Executive Committee met once in 2003 and its decisions were ratified by the full Board at the next succeeding regularly scheduled Board meeting. One member was not able to attend this Executive Committee meeting.

Governance and Nominating Committee

Members: The Governance and Nominating Committee consists of **Douglas D. Baldwin**, **Kevin S. Dunne**, **Roland Priddle¹** and **Lawrence G. Tapp**, all of whom are unrelated, independent directors.

Mandate: The primary roles and responsibilities of the Governance and Nominating Committee include:

- developing a set of corporate governance principles applicable to the Company and reviewing and approving the Company's annual disclosure of corporate governance compliance,
- establishing a long-term plan for composition of the Board,
- establishing a process for identifying, recruiting and appointing new directors and recommending nominees for election to the Board,
- reviewing and recommending the education and orientation program for new Board members,
- reviewing periodically the size of the Board to ensure its continued effectiveness,
- assessing the effectiveness of, and ensuring there is a succession plan for, the Chairman of the Board,
- reviewing and determining director compensation to ensure such compensation properly reflects the responsibilities and risks involved in being a director,
- considering and approving stock option grants in accordance with the Director Stock Option Plan to directors of the company who are not employed on a permanent basis by the Company,
- reviewing the purpose of, and recommending grants under, the Deferred Share Unit Plan,
- reviewing the general responsibilities and function of the Board, its committees and the roles of the Chairman of the Board and the Chief Executive Officer,
- assessing the needs of the Board in terms of frequency, location and conduct of Board and committee meetings,
- considering requests from individual directors or committees to engage outside advisors, and
- considering, and when appropriate, granting waivers from the application of the Code on Business Conduct to executive officers and directors. Any such waivers shall be promptly disclosed to shareholders.

Activities: The Governance and Nominating Committee met seven times in 2003. Two members were each unable to attend one meeting of the Committee.

Note:

¹ Denotes Committee Chair.

Management Succession and Compensation Committee

Members: The Management Succession and Compensation Committee consists of **Douglas D. Baldwin**, **Al L. Flood¹**, **Lawrence G. Tapp** and **Stella M. Thompson**, all of whom are unrelated, independent directors.

Mandate: The primary roles and responsibilities of the Management Succession and Compensation Committee include:

- reviewing succession plans for key management positions within the Company,
- reviewing management development and staffing plans, compensation, pension and benefit plans,
- leading the process for assessing the performance of the CEO,
- reviewing the employment agreements and annual performance contracts of the Company's Chief Executive Officer and executive officers,
- reviewing and approving the compensation levels of executive officers. In considering the Chief Executive Officer's compensation level, the Committee reviews and approves the corporate goals and objectives relevant to the Chief Executive Officer's compensation, evaluates the Chief Executive Officer's performance in light of those goals and objectives, and determines and approves the Chief Executive Officer's compensation level based on this evaluation,
- reviewing and approving employee stock option grants in accordance with the terms of the Employee Stock Option Plan,
- reviewing human resource strategies and policies, and
- producing the Company's disclosure of executive compensation.

Activities: The Management Succession and Compensation Committee met five times in 2003. All members attended each meeting of the Committee.

Pension Funds Committee

Members: The Pension Funds Committee consists of **Kevin S. Dunne**, **Dale G. Parker**, **Roland Priddle** and **Stella M. Thompson¹**, all of whom are unrelated, independent directors.

Mandate: The primary roles and responsibilities of the Pension Funds Committee include:

- approving the investment objectives and policy of the Company's pension plans,
- reviewing the investment strategy, risk profile and performance of the plans and approving the asset class allocations of the plans,
- approving the appointment and termination of investment managers and reviewing costs associated with the plan administration, and
- reviewing and approving annual financial statements and management reports of each plan.

Activities: The Pension Funds Committee met twice in 2003. All members attended each meeting of the Committee.

Reserves Committee

Members: The Reserves Committee consists of **Douglas D. Baldwin**, **Kevin S. Dunne** and **Charles W. Wilson¹**, all of whom are unrelated, independent directors.

Mandate: The primary roles and responsibilities of the Reserves Committee include:

- reviewing the Company's procedures relating to the disclosure of information with respect to oil and gas activities,
- reviewing the Company's procedures for providing information to the qualified reserves evaluator or auditor who reports on reserves data,
- meeting with management and the qualified reserves evaluator or auditor to review the reserves data and the report of the qualified reserves evaluator or auditor and to determine whether any restrictions affect the ability of the qualified reserves evaluator or auditor to report on reserves data without reservation,
- reviewing and recommending to the Board for approval the content and filing of the Company's annual statement of reserves data and other oil and gas information,
- reviewing and recommending to the Board for approval the filing of the annual report on reserves data by the qualified reserves evaluator or auditor, and
- reviewing and recommending to the Board for approval the content and filing of the Company's annual report of management and directors on oil and gas disclosure.

Activities: The Reserves Committee was formed in July 2003 and met twice in 2003. All members attended each meeting of the Committee.

Note:

¹ Denotes Committee Chair.

Roles and Responsibilities of the Chairman of the Board

The principal role of the Chairman of the Board is to manage and to provide leadership to the Board of Directors. The Chairman is accountable to the Board and acts as a direct liaison between the Board and management of the Company. In addition, the Chairman acts as a communicator for Board decisions where appropriate.

Other duties and responsibilities of the Chairman include:

- providing independent advice and counsel to the Chief Executive Officer,
- ensuring that the directors are properly informed and that sufficient information is provided to enable the directors to form appropriate judgments,
- developing and setting the agendas for meetings of the Board, in concert with the Chief Executive Officer,
- recommending to the Board the appointment of members to the committees after consultation with the directors, management and the Governance and Nominating Committee, and
- assessing and making recommendations annually regarding the effectiveness of the Board, committees of the Board and individual directors.

Roles and Responsibilities of the Chief Executive Officer

The Chief Executive Officer is responsible for leading the development and execution of the Company's long term strategy with a view to creating shareholder value. The Chief Executive Officer's leadership role also entails being ultimately responsible for all day-to-day management decisions and for implementing the Company's long and short term plans. The Chief Executive Officer acts as a direct liaison between the Board and management of the Company and communicates to the Board on behalf of management. The Chief Executive Officer also communicates on behalf of the Company to shareholders, employees, Government authorities, other stakeholders and the public.

Other duties and responsibilities of the Chief Executive Officer include:

- leading the development of the Company's strategy, and leading and overseeing the implementation of the Company's long and short term plans in accordance with its strategy,
- assessing the principal risks of the Company and to ensure that these risks are being monitored and managed,
- ensuring effective internal controls and management information systems are in place,
- ensuring that the Company maintains high standards of corporate citizenship and social responsibility wherever it does business,
- in concert with the Chairman, developing Board agendas, and
- abiding by specific internally established control systems and authorities, leading by personal example and encouraging all employees to conduct their activities in accordance with all applicable laws and the Company's standards and policies, including its environmental, safety and health policies.

In addition, the Chief Executive Officer is made directly responsible for achieving the goals of the Company through an annual performance contract, which sets out specific financial, operational, long-term and short-term strategic and leadership goals. Please see the section headed "Summary of Executive Compensation" for a discussion of how the Chief Executive Officer's compensation is directly linked to achievement of the goals set out in his annual performance contract.

Director Share Ownership Policy

In August 1998, the Board adopted a program regarding director ownership of Company shares. The program requires directors to own at least 2,500 Talisman shares and sets out a timeframe over which that accumulation should occur. All nominees for election as director currently own Talisman shares that meet or exceed the levels of ownership set by the internal program. In addition, the Company adopted a Deferred Share Unit Plan for non-employee directors effective January 1, 2001 to support the alignment of director and shareholder interests. More information about the Deferred Share Unit Plan is provided under the heading "Remuneration of Directors" in the Circular.

Policy on Business Conduct and Ethics

In December 2003, Talisman revised its longstanding code of ethics to better reflect the evolving area of corporate responsibility and to incorporate the latest corporate governance requirements. Entitled the "Policy on Business Conduct and Ethics", the code is applicable to all directors, officers and employees of the Company, and can be obtained from Talisman's website at www.talisman-energy.com or upon request from: Investor and Corporate Communications Department, Talisman Energy Inc., Suite 3400, 888 Third Street S.W., Calgary, Alberta, T2P 5C5, e-mail: t1m@talisman-energy.com.

Management Performance

The terms of the mandate of the Board ensure that the Company annually confirms or redetermines its long-term strategy and strategic objectives and sets its budget and development plan for the ensuing year. This process produces specific annual goals for the Company that are further developed into specific contracts for each of the executive officers of the Company based upon that executive officer's role in the Company. Through this process, each executive officer (including the President and Chief Executive Officer) individually, and the executive officers as a whole, are made directly responsible for achieving the annual goals of the Company. A significant portion of the annual compensation of each executive officer is based upon achieving these Company and individual goals.

Shareholder Communications

Talisman's shareholder communications program specifically adopts the principles of timely, accurate and efficient disclosure of information concerning the Company to all shareholders. In addition to the required annual, quarterly and timely reporting of information, the Company regularly makes presentations to industry analysts and investors. The Company also meets informally upon request with investors and analysts, provided however, that in any such meeting, the Company strictly adheres to all applicable laws relating to selective disclosure of material information. The Company's Investor Relations and Corporate Communications Department has the specific mandate of responding in a timely manner to all inquiries received from shareholders, analysts and potential investors. Shareholder inquiries or suggestions are forwarded to the appropriate person or to senior management. Shareholders may also obtain corporate information on the Company's external website at www.talisman-energy.com.

TSX Corporate Governance Guidelines

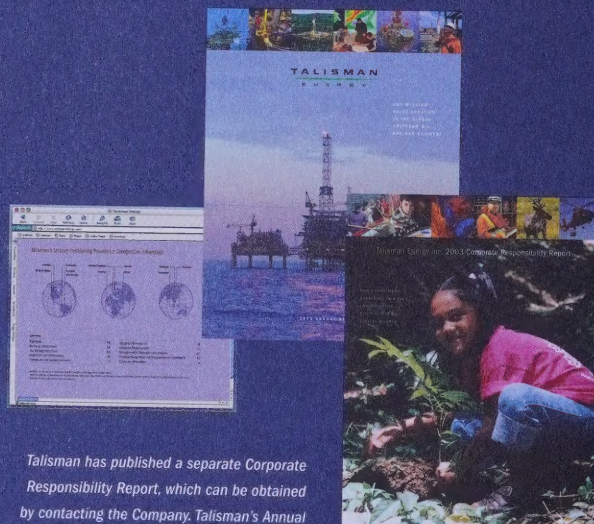
The following is a tabular confirmation of Talisman's compliance with each of the existing TSX corporate governance guidelines. Information about how the Company complies with each guideline is provided in the preceding narrative statement.

Talisman's

Compliance TSX Corporate Governance Guidelines

✓	(1) The board of directors of every corporation should explicitly assume responsibility for the stewardship of the corporation and, as part of the overall stewardship responsibility, should assume responsibility for the following matters:
✓	(a) adoption of a strategic planning process;
✓	(b) the identification of the principal risks of the corporation's business and ensuring the implementation of appropriate systems to manage these risks;
✓	(c) succession planning, including appointing, training and monitoring senior management;
✓	(d) a communications policy for the corporation; and
✓	(e) the integrity of the corporation's internal control and management information systems.
✓	(2) The board of directors of every corporation should be constituted with a majority of individuals who qualify as unrelated directors. An unrelated director is a director who is independent of management and is free from any interest and any business or other relationship which could, or reasonably be perceived to, materially interfere with the director's ability to act with a view to the best interests of the corporation other than interests and relationships arising from shareholding. A related director is a director who is not an unrelated director. If the corporation has a significant shareholder, in addition to a majority of unrelated directors, the board should include a number of directors who do not have interests in or relationships with either the corporation or the significant shareholder and which fairly reflects the investment in the corporation by shareholders other than the significant shareholder. A significant shareholder is a shareholder with the ability to exercise a majority of the votes for the election of the board of directors.
✓	(3) The application of the definition of "unrelated director" to the circumstances of each individual director should be the responsibility of the board which will be required to disclose on an annual basis whether the board has a majority of unrelated directors or, in the case of a corporation with a significant shareholder, whether the board is constituted with the appropriate number of directors which are not related to either the corporation or the significant shareholder. Management directors are related directors. The board will also be required to disclose on an annual basis the analysis of the application of the principles supporting this conclusion.
✓	(4) The board of directors of every corporation should appoint a committee of directors composed exclusively of outside, i.e., non-management directors, a majority of whom are unrelated directors, with the responsibility for proposing to the full board new nominees to the board and for assessing directors on an ongoing basis.

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- ✓ (5) Every board of directors should implement a process to be carried out by the nominating committee or other appropriate committee for assessing the effectiveness of the board as a whole, the committees of the board and the contribution of individual directors.
 - ✓ (6) Every corporation, as an integral element of the process of appointing new directors, should provide an orientation and education program for new recruits to the board.
 - ✓ (7) Every board of directors should examine its size and, with a view to determining the impact of the number upon effectiveness, undertake where appropriate, a program to reduce the number of directors to a number which facilitates more effective decision making.
 - ✓ (8) The board of directors should review the adequacy and form of the compensation of directors and ensure the compensation realistically reflects the responsibilities and risk involved in being an effective director.
 - ✓ (9) Committees of the board of directors should generally be composed of outside directors, a majority of whom are unrelated directors, although some board committees, such as the executive committee, may include one or more inside directors.
 - ✓ (10) Every board of directors should expressly assume responsibility for, or assign to a committee of directors the general responsibility for, developing the corporation's approach to governance issues. This committee would, amongst other things, be responsible for the corporation's response to these governance guidelines.
 - ✓ (11) The board of directors, together with the CEO, should develop position descriptions for the board and for the CEO, involving the definition of the limits to management's responsibilities. In addition, the board should approve or develop the corporate objectives which the CEO is responsible for meeting.
 - ✓ (12) Every board of directors should have in place appropriate structures and procedures to ensure that the board can function independently of management. An appropriate structure would be to (i) appoint a chair of the board who is not a member of management with responsibility to ensure the board discharges its responsibilities or (ii) adopt alternate means such as assigning this responsibility to a committee of the board or to a director, sometimes referred to as the "lead director". Appropriate procedures may involve the board meeting on a regular basis without management present or may involve expressly assigning the responsibility for administering the board's relationship to management to a committee of the board.
 - ✓ (13) The audit committee of every board of directors should be composed only of outside directors. The roles and responsibilities of the audit committee should be specifically defined so as to provide appropriate guidance to audit committee members as to their duties. The audit committee should have a direct communication channel with the internal and external auditors to discuss and review specific issues as appropriate. The audit committee duties should include oversight responsibility for management reporting on internal control. Although it is management's responsibility to design and implement an effective system of internal control, it is the responsibility of the audit committee to ensure that management has done so.
 - ✓ (14) The board of directors should implement a system which enables an individual director to engage an outside adviser at the expense of the corporation in appropriate circumstances. The engagement of the outside advisor should be subject to the approval of an appropriate committee of the board.
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Talisman has published a separate Corporate Responsibility Report, which can be obtained by contacting the Company. Talisman's Annual and Corporate Responsibility reports can also be viewed on our website.

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